UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC	)	**Docket Nos. RM13-_____**
RELIABILITY CORPORATION	)	**RM12-1-000**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF MODIFIED TRANSMISSION PLANNING RELIABILITY STANDARDS IN THE CASE OF SYSTEM PERFORMANCE FOLLOWING LOSS OF A SINGLE BULK ELECTRIC SYSTEM ELEMENT

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February 28, 2013

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5 of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") regulations, 18 C.F.R.§ 39.5 (2012), and in response to the Commission's remand in Order No. 762[2] (the "Remand") and concerns identified in the Commission's Notice of Proposed Rulemaking issued in Docket No. RM12-1-000,[3] the North American Electric Reliability Corporation ("NERC")[4] hereby requests Commission approval of the following changes to the requirements and processes for planned load shed in the event of a single Contingency that are identified in a revised footnote,[5] and Attachment 1 to that

[1] 16 U.S.C. § 824o (2006).

[2] *Transmission Planning Reliability Standards*, Order No. 762, 139 FERC ¶ 61,060 (2012). ("Order No. 762"), *order on reconsideration*, 140 FERC ¶ 61,101 (2012).

[3] *Transmission Planning Reliability Standards*, 139 FERC ¶ 61,059 (2012) ("TPL NOPR").

[4] The Commission certified NERC as the Electric Reliability Organization ("ERO") in accordance with Section 215 of the Federal Power Act pursuant on July 20, 2006 in Docket No. RR06-1-000. *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062 (2006) ("ERO Certification Order").

[5] Capitalized terms used but not defined in this Petition are intended to have the same meaning given to such terms in the Proposed Standards or the *Glossary of Terms Used in NERC Reliability Standards*, available at: http://www.nerc.com/files/Glossary_of_Terms.pdf.

footnote (the "Footnote").[6] NERC is also requesting Commission approval of revisions to the Standards that correspond to the Footnote revisions included in this Petition and other related documents:

- Pursuant to the TPL NOPR, NERC is requesting approval of the **<u>proposed TPL Standard TPL-001-4</u>** (referred to herein as the "Consolidated TPL Standard") that was filed with the Commission as TPL-001-2 on October 19, 2011 in Docket No. RM12-1-000 and is currently pending approval (**Exhibit A**).

- **<u>Implementation Plan for the Consolidated TPL Standard</u>** that was filed with the Commission on October 19, 2011 in Docket No. RM12-1-000 and is currently pending approval (**Exhibit B**).

- **The proposed definitions included in the Consolidated TPL Standard** that were filed with the Commission on October 19, 2011 in Docket No. RM12-1-000 and are currently pending approval **(included in Exhibit A)**.

- **The proposed Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the Consolidated TPL Standard** that were filed with Commission for approval on October 19, 2011 in Docket No. RM12-1-000 and are currently pending approval **(included in Exhibit A)**.

- **<u>Retirement of the following Reliability Standards</u>** (the currently-effective versions of the individual TPL standards (collectively, the "Current TPL Standards")), concurrently with the effectiveness of the proposed TPL-001-4 Reliability Standard:

    - TPL-001-0.1;
    - TPL-002-0b;
    - TPL-003-0a; and
    - TPL-004-0.

- The withdrawal of two pending TPL Reliability Standards, TPL-005-0 (Regional and Interregional Self-Assessment Reliability Reports) and TPL-006-0.1 (Data from the Regional Reliability Organization Needed to Assess Reliability) because the requirements from these Reliability Standards have been moved to Sections 803 and 804 of the NERC Rules of Procedure. These proposed

[6] Footnote 'b' included as part of TPL-002-2b is in all material respects the same as the proposed footnote 12 included as part of Reliability Standard TPL-001-4.

withdrawals were addressed in NERC's October 19, 2011 petition filed in FERC Docket No. RM12-1-000.

The Consolidated TPL Standard supersedes the Current TPL Standards by consolidating the four Version 0 TPL standards (TPL-001-0.1; TPL-002-0b; TPL-003-0a; and TPL-004-0) into the proposed Consolidated TPL Standard. The Consolidated TPL Standard includes the proposed Footnote as Note 12, which is the only addition to the Consolidated TPL Standard since it was initially filed with FERC for approval on October 19, 2011.

In the event the Commission does not approve the Consolidated TPL Standard, NERC requests approval of the following:

- Pursuant to the Remand, **four Proposed Transmission Planning ("TPL") Reliability Standards** (together, the "Individual TPL Standards"):
    - TPL-001-3 ((System Performance Under Normal (No Contingency) Conditions (Category A))) (**Exhibit C**);
    - TPL-002-2b (System Performance Following Loss of a Single Bulk Electric System Element (Category B)) (**Exhibit C**);
    - TPL-003-2a (System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)) (**Exhibit C**);
    - TPL-004-2 (System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)) (**Exhibit C**).
- **Implementation Plan for TPL-001-3, TPL-002-2b, TPL-003-2a, and TPL-004-2** (**Exhibit D**).
- **Retirement of the following Reliability Standards** concurrently with the effectiveness of its corresponding Individual TPL Standard:
    - TPL-001-0.1;
    - TPL-002-0b;
    - TPL-003-0a; and

- TPL-004-0.

Collectively, the Consolidated TPL Standard and the Individual TPL Standards are referred to herein as the "Proposed TPL Standards".

I. **<u>EXECUTIVE SUMMARY</u>**

The limited but critical change to the Proposed TPL Standards and the purpose of this petition is to revise the Footnote to address concerns articulated by the Commission, most recently in Order No. 762 and the concurrently issued TPL NOPR. As described in greater detail in Section V of this petition, and the supporting materials included with this petition, the Footnote provides specific parameters for the permissible use of planned shedding of Firm Demand to address Bulk Electric System ("BES") performance issues, including:

- Firm limitations on the maximum amount of load that may be planned to be shed,
- Safeguards to ensure against inconsistent results and arbitrary determinations that allow for the planned shedding of Firm Demand, and
- A more specifically defined, open and transparent, verifiable, and enforceable stakeholder process designed to ensure that there will be no Adverse Reliability Impacts caused by a request to plan for Firm Demand interruption, subject in certain cases to a final review by the ERO.

The Footnote was developed in accordance with Section 300 of NERC's Rules of Procedure (Reliability Standards Development) and the NERC Standard Processes Manual. The NERC Board of Trustees approved the Footnote and its inclusion in the Proposed TPL Standards on February 7, 2013.

As revised, the Footnote and the Proposed TPL Standards will improve reliability by providing specific procedural and substantive parameters for the proposed stakeholder process, defining the circumstances in which a plan for non-consequential load loss could be utilized, and establishing safeguards to ensure against inconsistent results and arbitrary determinations in the case of planned interruption of Firm Demand.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[7]

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[7] Persons to be included on the Commission's service list are identified by an asterisk.

III. GENERAL BACKGROUND

Provided below are the following: (a) an explanation of the regulatory background for NERC Reliability Standards; (b) an explanation of the NERC Reliability Standards development procedure; and (c) the procedural history of the TPL Reliability Standards.

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[8] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the nation's Bulk Power System, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215 of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards.[9]

Section 215(d)(5) of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard for the Commission's review and approval. However, FPA Section 215(c)(2)(D) requires the ERO to develop that standard, using "a process that provides for reasonable notice and opportunity for public comment, due process, openness, and balance of interests." Pursuant to Section 215(d)(2) of the FPA and Section 39.5(c) of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to

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[8] 16 U.S.C. § 824o (2006).

[9] *See* Section 215(b)(1)("All users, owners and operators of the bulk-power system shall comply with reliability standards that take effect under this section.").

the content of a Reliability Standard. In Order No. 693,[10] the Commission noted that it would defer to the "technical expertise" of the ERO with respect to the content of a Reliability Standard and explained that, through the use of directives, it provides guidance, but does not dictate an outcome. Further, it stated that the Commission will consider an alternative approach to a Commission proposal, example or directive, provided that the ERO demonstrates that the alternative will address the Commission's underlying concern or goal as efficiently and effectively as the Commission's proposal, example, or directive.[11]

Section 39.5(a) of the Commission's regulations requires the ERO to request the Commission's approval for each new Reliability Standard that the ERO proposes to become mandatory and enforceable in the United States, as well as each modification to an existing Reliability Standard that the ERO proposes to be made effective. The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest.

Order No. 672[12] provides guidance on the factors the Commission will consider when determining whether proposed Reliability Standards meet the statutory criteria to ensure that they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Each of those factors is addressed in **Exhibit E**.

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[10] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[11] *See* Order No. 693 at PP 31, 186-187.

[12] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, ("Order No. 672") 114 FERC ¶ 61,104 (2006).

B. NERC Reliability Standards Development Procedure

NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual. In its ERO Certification Order, the Commission found that NERC's rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies certain of the criteria for approving Reliability Standards. The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk Power System. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a Reliability Standard before the Reliability Standard is submitted to the Commission for approval. The Footnote and its inclusion in the Proposed TPL Standards were approved by the NERC Board of Trustees on February 7, 2013.

C. Procedural History of the TPL Standards

1. Order No. 693 Directive

Each of the Current TPL Standards was first approved by the Commission in Order No. 693, which approved 83 of 107 Reliability Standards filed by NERC. In approving the Reliability Standards, the Commission directed modifications to 56 of the Reliability Standards, including modifications to the TPL Standards. Pertinent to this petition, the Commission stated that TPL Standards should not allow an entity to plan for the loss of non-consequential firm load in the event of a single Contingency.[13]

[13] Order 693 at P 1794.

Accordingly, the Commission directed NERC to develop certain modifications to the TPL Standards, including a clarification to the Footnote.

In a subsequent order, however, the Commission clarified that a regional difference in a plan for the loss of firm service would be acceptable, but only in limited circumstances, or in a specific case for which there is technical justification.[14] Specifically, the Commission stated that "a regional difference, or a case-specific exception process that can be technically justified, to plan for the loss of firm service at the fringes of various systems would be an acceptable approach."[15] In the June 2010 Order, the Commission granted NERC an extension of time, to March 31, 2011, to submit a modification to TPL-002-0 responsive to the Commission's directive in Order No. 693.[16]

2. *Order No. 762* Remand

On March 31, 2011, NERC filed a petition for approval of revisions to the Current TPL Standards, specifically intended to clarify the Footnote as directed in Order No. 693 (the "March 2011 Filing"). However, in response to the March 2011 Filing, the Commission concluded, in Order No. 762, that the proposed revisions to the Footnote did not meet the Commission's Order No. 693 directives, nor did the revisions achieve "an equally effective and efficient alternative".[17] Accordingly, the Commission remanded the March 2011 Filing to NERC, directing NERC to revise TPL-002-1b (the Footnote) to address the Commission's concerns described in Order No. 762, subject to the additional

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[14] *Mandatory Reliability Standards for the Bulk Power System*, 131 FERC ¶ 61,231, at P 21 (2010) ("June 2010 Order").

[15] *Id.*

[16] *Id.* at P 26.

[17] Order No. 762 at P 12.

guidance provided therein.[18] In response to a NERC request for reconsideration,[19] the Commission permitted NERC to address the Commission's concerns using NERC's regular process for developing Reliability Standards, rather than by invoking NERC's Expedited Standards Development Process, based on NERC's commitment to deliver a new Footnote to the NERC Board of Trustees for a vote at the Board's February 2013 meeting.[20]

Additionally, in Order No. 762, the Commission directed NERC to "identify the specific instances of any planned interruptions of Firm Demand under footnote "b" and how frequently the provision has been used."[21] FERC directed NERC to use Section 1600 of its Rules of Procedure to obtain information from users, owners, and operators of the Bulk Power System to provide this requested data and to submit the information to FERC with this petition.[22] Accordingly, the summary results of the Section 1600 Data Request ("Data Request") on the instances of footnote b use under the Current TPL Standards are included as **Exhibit F** to this petition.

NERC recognizes that because the Footnote proposed in this filing is different from the footnote b included in the existing TPL standards, data does not yet exist on the frequency of instances of planned interruption of Firm Demand under the new Footnote. For this reason, NERC is committing to monitor use of the Footnote and will report the results of this monitoring after the first two years of the Footnote's implementation.

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[18] *Id.* at P 66.

[19] *Request of the North American Electric Reliability Corporation for Reconsideration, or in the Alternative, Rehearing of* Order *Remanding the Transmission Planning Reliability Standards,* Docket No. RM11-18-000 (May 21, 2012).

[20] *Transmission Planning Reliability Standards*, 140 FERC ¶ 61,101 at P 6 (2012).

[21] Order No. 762 at P 20.

[22] *Id.*

3. <u>Notice of Proposed Rulemaking – Consolidated TPL Standard</u>

In matters related to the Footnote, NERC filed a petition on October 19, 2011 in Docket No. RM12-1, seeking approval of the Consolidated TPL Standard that combines the four Current TPL Standards into a single standard (*i.e.*, filed as TPL-001-2 and included in this petition as TPL-001-4), as well as approval of an associated implementation plan, VRFs, and VSLs, and five new definitions to be added to the NERC Glossary of Terms. NERC also requested approval of the retirement of the four Current TPL Standards and the withdrawal of two pending TPL Standards.[23] The proposed TPL-001-2 included the Footnote that was the subject of the Remand, which was adapted for the new standard without modifying the technical content and intent of the Footnote, and which was subject to ongoing consideration and refinement in Project 2010-11 (TPL Table 1 Order Project).[24] In light of the inclusion of the Footnote, however, and "notwithstanding improvements contained in other provisions of TPL-001-2", the Commission issued the TPL NOPR, indicating that it had "no option other than to propose to remand the entire Reliability Standard [TPL-001-2]".[25] The Commission added, however, that "resolution of this one matter will allow the industry, NERC and the Commission to go forward with the consideration of other improvements contained in

[23] The pending TPL Standards are TPL-005-0 (Regional and Interregional Self-Assessment Reliability Reports) and TPL-006-0.1 (Data from the Regional Reliability Organization Needed to Assess Reliability). The requirements from these Standards have been moved to Section 803 and 804 of the NERC Rules of Procedure.

[24] Project 2011-10 addressed Commission orders that which required NERC to clarify the Footnote.

[25] TPL NOPR at P 2.

proposed Reliability Standard TPL-001-2."[26] The TPL NOPR and TPL-001-2 remain pending before the Commission. It is for this reason that NERC has included the proposed revisions to the Consolidated TPL Standard that are intended to replace the proposed TPL-001-2 standard pending with the Commission, the proposed revisions to the Individual TPL Standards to be approved in the event the Consolidated TPL Standard is not approved, and the documents corresponding to the Proposed TPL Standards with this petition to revise the Footnote.

IV. SUMMARY OF THE TPL RELIABILITY STANDARDS DEVELOPMENT PROCEEDINGS

The highlights of the development process for the proposed Footnote to be included in both the Consolidated TPL Standard and the Individual TPL Standards are summarized below. **Exhibit G** contains a Summary of the Development Authorization, Posting, and Balloting History of the Footnote and the Proposed Standards since the Remand. **Exhibit H** contains the Consideration of Comments Reports created during the development of the Proposed Standards post-Order 762. **Exhibit I** contains the complete post-Order No. 762 record of development for the Proposed Standards.

A. Overview of the Standard Drafting Team

When evaluating modified Reliability Standards, the Commission is expected to give "due weight" to the technical expertise of the ERO.[27] The technical expertise of the ERO is derived from the Standard Drafting Team ("Drafting Team"). For this project, the Drafting Team consisted of 14 industry experts with a wealth of diverse industry

[26] *Id.* at P 3.
[27] FPA § 215(d)(2); 16 U.S.C. § 824o(d)(2) (2012).

experience across North America, including both the continental United States and Canada. A Drafting Team roster and member biographical information is included in **Exhibit J**.

B. **Post-*Order No. 762* Development History**

In response to Order No. 762 and the TPL NOPR, the Standards Committee directed the Drafting Team to respond quickly to directives in those orders, as well as the prior directives in Order No. 693, to address planned load shed under limited circumstances for single Contingencies. The Footnote was revised to meet those directives, as well as to comments received following four rounds of public comment and three rounds of balloting, which concluded when the January 2013 recirculation ballot achieved a quorum of 88.55% and a weighted stakeholder segment approval of 69.63%.[28]

C. **Board of Trustees Approval**

The final drafts of the stakeholder-approved Proposed TPL Standards, each of which contains the Footnote revised in response to the Remand, together with a NERC staff summary of the revisions, underlying history, minority issues and associated Drafting Team responses, and additional background information, were presented to NERC's Board of Trustees for approval on February 7, 2013. The Board of Trustees approved the revisions to the Footnote incorporated into the Proposed TPL Standards, and directed NERC staff to make the requisite filings with applicable regulatory authorities.

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[28] *See* **Exhibit G** to this petition.

V. FOOTNOTE REQUIREMENTS AND PROCESSES, ENFORCEABILITY, AND IMPROVEMENTS

Provided below are the following: (a) an explanation of the Footnote Requirements and processes; (b) an explanation of the enforceability of the TPL Reliability Standards; and (c) an explanation of the improvements included in the Proposed Standards.

A. Footnote Requirements and Processes

1. Proposed Stakeholder Process

The Footnote's stakeholder process is well defined by specific parameters and required information sharing. The main body of the Footnote states that the objective of the planning process is to minimize the likelihood and magnitude of interruption of Firm Demand following Contingency events, while describing the conditions that would be allowed for dropping non-consequential load and meeting the overarching threshold value for any planned load shed, as set forth in the Footnote.

Section I of Attachment 1 to the Footnote sets forth the conditions that must be satisfied to establish open and transparent stakeholder meetings, which is the first step an entity must meet in invoking use of the Footnote. Section I also details who must be invited, the process for notifying interested parties, what information must be supplied to them, a process for presenting stakeholder questions and concerns, and a method for resolving disputes. The stakeholder meetings must be held for any circumstance for which the planned utilization of the Footnote would be applicable. Further, based on the data provided in response to the Data Request, the standard drafting team determined that a planned load shed up to 25 MW should be resolved within the described stakeholder process with no further review required.

Section I also provides that an entity does not have to repeat the stakeholder process for a specific application of the Footnote with respect to subsequent Planning Assessments unless conditions spelled out in Section II have materially changed for that specific application. This language was intentionally included to be consistent with Requirement R2.6 of the Consolidated TPL standard, which allows for past studies to be used to support Planning Assessments if they meet certain conditions, including for steady state, short circuit, or Stability analysis, when *no material changes* occur to the System.

Similarly, in the proposed Footnote, in order to lessen the burden on industry, if conditions in which the Footnote is utilized have not materially changed for that specific application, the Drafting Team determined that the entity should not have to repeat the stakeholder process required under the proposed Footnote. This approach builds in flexibility and allows entities to use operating judgment in determining what constitutes a "material change" (*e.g.*, thereby allowing the entity to take into account regional and operating differences).

The proposed Requirement R8 of the Consolidated TPL Standard includes an additional safeguard to monitoring Planning Assessments by requiring that Planning Assessments be shared with adjacent Planning Coordinators, Transmission Planners, or other entities that demonstrate a reliability related need. Requirement R8 provides:

> Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Requirement R8 of the Consolidated TPL Standard therefore provides a system of checks and balances on entities' Planning Assessments from neighboring entities in the overall transmission planning process of which the proposed Footnote is one small part.

Additionally, in Order No. 762, FERC asked how the ERO would determine the cumulative effect of load shedding if there is no annual review of load shedding under the Footnote due to the lack of a material change. Use of the Footnote itself is not representative of every instance of possible planned load shed because multiple contingency situations, for example, allow load shed under certain circumstances. However, Requirement R8 of the proposed Consolidated TPL Standard, described above, should help enable peer oversight of what is contained in the assessments. This will give Planning Coordinators, Transmission Planners, and other entities the ability to monitor any potential cumulative effect of load shedding.

Section II of Attachment 1 specifies the information that has to be provided to stakeholders with respect to the purpose and scope of the proposed Firm Demand interruption under the Footnote. This information is designed to adequately demonstrate to stakeholders why and how the load shed alternative was selected as the best planning choice, while allowing stakeholders to see all of the variables that were involved in selecting the load shed alternative, including costs, frequency, and duration of the planned load shed, mitigation plans, explanation of the effect on public health, safety, and welfare, and adherence to the transmission planning performance standards and the Footnote.

Section III of Attachment 1 describes the process for planned load shed greater than 25 MW. Specifically, planned load sheds between 25 MW and 75 MW, or any planned load shed at the 300 kV level or above would receive greater scrutiny by regulatory authorities and the ERO. The 300 kV voltage level is based on the previously submitted Extra High Voltage ("EHV") level that had been proposed in TPL-001-2 which raised the bar for transmission planning for such EHV facilities. The 75 MW limit was derived from information received in response to the Data Request and is the maximum amount of planned load shed allowed by the Footnote for U.S. entities. Importantly, system performance after utilization of the footnote must continue to meet transmission planning performance standards, which do not allow for instability, uncontrolled separation, or cascading failures.

2. Circumstances in which Non-Consequential Load Loss may be Allowed

As noted above, the proposed Footnote provides specific limitations on how much non-consequential load a responsible entity can plan to shed for a single Contingency event, while defining the terms and conditions under which such planned load shed could be justified – in an open and transparent public forum. The Data Request results provide the technical basis for establishing the load shed amount limitations. In addition, the Footnote sets out what information must be provided to the affected stakeholders to enable them to consider the costs associated with the proposed plans, as well as any alternatives. The combination of amount limitations and other considerations, such as costs and alternatives, guards against a determination based solely on a quantitative threshold becoming an acceptable *de facto* interpretation of planned Firm Demand. Therefore, the procedures in the Footnote would enable acceptable, but limited, circumstances of planned Firm Demand interruptions after a thorough stakeholder review and approval and, in some cases, ERO review.

3. **Safeguards Against Inconsistent Results and Arbitrary Determinations**

To ensure against inconsistent results and arbitrary determinations, the Footnote requires that, subject to defined thresholds (voltage level of Contingency greater than 300 kV or a planned interruption greater than or equal to 25 MW), entities with regulatory oversight over retail electric service that would be affected by a Firm Demand interruption ("Retail Regulator") must agree to the use of the Footnote. Once the Retail Regulator has indicated that it does not object to the Firm Demand interruption under the Footnote, the responsible entity must submit the Section II information included in the stakeholder process to the ERO. The ERO then must determine whether or not there are any Adverse Reliability Impacts caused by the request to use the Footnote, thus meeting the ERO's review and oversight function.[29]

The ERO's oversight role will be focused on determining whether there are any Adverse Reliability Impacts. "Adverse Reliability Impact" is defined in the NERC Glossary of Terms as "[t]he impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection." Consistent with this definition, NERC's oversight of uses of the Footnote that exceed a voltage level greater than 300 kV or a planned interruption greater than or equal to 25 MW will be

[29] The proposed Footnote preserves, to the extent practicable, the role of Retail Regulators. The Footnote limits the ERO's role in local planning process, but still allows the ERO to review possible Adverse Reliability Impacts.

focused on whether any of the conditions included in the definition of Adverse Reliability Impact are met.

B. Enforceability of the TPL Standards; VRFs and VSLs Unchanged

The proposed TPL Standards include measures that support each Reliability Standard requirement, by clearly identifying what is required and how the requirement will be enforced, thus ensuring that the requirements will be enforced in a clear, consistent, and non-preferential manner, and without prejudice to any party.[30] In addition, the revised Footnote, in providing specific parameters for the permissible use of planned shedding of Firm Demand, ensures against inconsistent results and arbitrary determinations. The Footnote accomplishes this by providing a defined, open and transparent, verifiable, and enforceable stakeholder process that ensures there are no Adverse Reliability Impacts on the BES. The VSLs also provide further guidance on how the ERO will enforce the requirements of the Standard.

The proposed VRFs and VSLs for the Consolidated TPL Standard were included in the petition filed with the Commission for approval on October 19, 2011. NERC hereby requests Commission approval of those VRFs and VSLs in response to this petition. As noted above, in the event the Commission does not approve the Consolidated TPL Standard, NERC is requesting Commission approval of the Individual TPL Standards as modified to include the Footnote. The Individual TPL Standards do

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

not modify the Commission-approved VRFs and VSLs included in the Current TPL Standards.

C. **Improvements Reflected in the Proposed Standards**

As discussed in more detail above, the Footnote addresses the Commission's concerns raised in Order No. 762 and the TPL NOPR. The proposed revision to the Footnote is an equally effective and efficient alternative to address the Commission's directive that must be given due consideration by the Commission. The Proposed TPL Standards would improve reliability by:

- Providing a blend of specific quantitative and qualitative parameters for the permissible use of planned shedding of Firm Demand to address BES performance issues;
- Providing a clear and concise definition of the process, including specific criteria and guidelines, that must be followed before a responsible entity may plan to shed load in the event of a single Contingency; and
- Providing additional safeguards to ensure that there will be no Adverse Reliability Impacts caused by a request to plan for Firm Demand interruption.

VI. <u>REQUESTED EFFECTIVE DATES</u>

As noted above, NERC requests that each of the Proposed TPL Standards become effective in accordance with the effective date provisions contained therein. NERC further requests that the Commission approve the retirement of the Current TPL Standards upon approval of the proposed Consolidated TPL Standard, or alternatively, upon approval of the proposed Individual TPL Standards. The corresponding proposed effective dates are just and reasonable and appropriately balance the urgency in the need to implement the Footnote in the Proposed TPL Standards against the reasonableness of the time allowed for those who must comply to develop the necessary procedures and take the necessary actions to reflect the requirements and processes identified in the Footnote. The proposed effective dates will allow affected entities adequate time to ensure compliance with the Footnote in accordance with Order No. 672.[31]

VII. CONCLUSION

Accordingly, and for the reasons set forth above, NERC respectfully requests that the Commission approve:

- the Proposed TPL Standards included in **Exhibits A and C,** effective as proposed therein and as described in this filing;
- the Implementation Plans included in **Exhibits B and D** as described in this filing; and
- the retirement of the Current TPL Standards concurrent with approval of either the proposed Consolidated TPL Standard or the Individual TPL Standards.

[31] Order No. 672 at P 333, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006) ("In considering whether a proposed Reliability Standard is just and reasonable, FERC will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.").

Respectfully submitted,

/s/ Holly A. Hawkins

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CERTIFICATE OF SERVICE

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

Dated at Washington, D.C. this 28th day of February, 2013.

/s/ Holly A. Hawkins

Holly A. Hawkins
Attorney for North American Electric Reliability Corporation

Exhibit A

Proposed Consolidated TPL Reliability Standard submitted for Approval

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-4**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
      ii. Loss of the use of a large body of water as the cooling source for generation.
      iii. Wildfires.
      iv. Severe weather, e.g., hurricanes, tornadoes, etc.
      v. A successful cyber attack.
      vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
   b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   e. 3Ø internal breaker fault.
   f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled ‘Initial Condition’) and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner’s planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, &

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	

A. Introduction

1. Title: Transmission System Planning Performance Requirements

2. Number: TPL-001-~~2~~4

3. Purpose: Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. Applicability:

4.1. Functional Entity

4.1.1. Planning Coordinator.

4.1.2. Transmission Planner.

5. Effective Date: Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where ~~no~~ regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption~~.~~ or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where ~~no~~ regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where ~~no~~ regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-~~2~~4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-~~2~~4:

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: ~~Lower~~Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: ~~Lower~~Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
    - a. Loss of a tower line with three or more circuits.[11]
    - b. Loss of all Transmission lines on a common Right-of-Way[11].
    - c. Loss of a switching station or substation (loss of one voltage level plus transformers).
    - d. Loss of all generating units at a generating station.
    - e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
    - a. Loss of two generating stations resulting from conditions such as:
        - i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
        - ii. Loss of the use of a large body of water as the cooling source for generation.
        - iii. Wildfires.
        - iv. Severe weather, e.g., hurricanes, tornadoes, etc.
        - v. A successful cyber attack.
        - vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
    - b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
    - a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    - b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    - c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    - d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    - e. 3Ø internal breaker fault.
    - f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process ~~should be~~is to minimize the likelihood and magnitude of Non-Consequential Load Loss following ~~Contingency~~planning events. ~~However, in~~In limited circumstances, Non-Consequential Load Loss may be needed ~~to address~~throughout the planning horizon to ensure that BES performance requirements~~. When~~ are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the ~~planning process~~Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss ~~is documented, including alternatives evaluated; and where the utilization of Non-Consequential Load Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments~~meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
in the non-US jurisdiction.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

    b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
    a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
    b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote ‘b’ in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	

Exhibit B

Implementation Plan for the Consolidated TPL Reliability Standard

Implementation Plan for TPL-001-4

Prerequisite Approvals

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

TPL-001-4 — Transmission System Planning Performance Requirements

In revising the TPL standards, the SDT is assuming that planners will receive valid data from the MOD standards link described in TPL-001-4, Requirement R1. Furthermore, there is a tacit assumption that future revisions of the MOD standards will include steps to validate MOD based data.

Revision to Sections of Approved Standards and Definitions

There are multiple new definitions in the proposed standard.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Compliance with Standards

Standard	Functions That Must Comply With the Associated Requirements	
TPL-001-4 — Transmission System Planning Performance Requirements	Transmission Planner	Planning Coordinator
	X X	

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

TPL-001-3, TPL-002-2b, TPL-003-2a, and TPL-004-2 are being retired as they are replaced in their entirety by TPL-001-4. TPL-005-0 and TPL-006-0.1 are being retired because their requirements are adequately covered by the revised TPL-001-4 and NERC's Rules of Procedure, Section 800. TPL-001-3, TPL-002-2b, TPL-003-2a, TPL-004-2, TPL-005-0 and TPL-006-0.1 are being retired on midnight of the day immediately prior to the Effective Date of TPL-001-4 in the particular jurisdictions in which TPL-001-4 is becoming effective. However, during this 24-month period, all aspects of TPL-001-3 through TPL-006-0.1 shall remain in effect for compliance monitoring. This 24 month period is to allow entities to develop, perform and/or validate new and/or modified studies, methodologies, assessments, procedures, etc. necessary to implement and meet the TPL-001-4 requirements. The specified effective dates are expected to allow sufficient time for proper assessment of the available options necessary to create a viable Corrective Action Plan that is compliant with the new Standard.

R1. This Requirement is related to maintaining System models and the data needed to do so. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

R7. This Requirement identifies an obligation to determine individual and joint responsibilities for performing studies needed to do the Planning Assessment. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes

into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

TPL-001-4 ‘raises the bar’ in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-3, TPL-002-2b, TPL-003-2a and TPL-004-2 because loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by many to allow such actions. As shown in Table 1 of TPL-001-4, the performance requirements associated with the following events represent “raising the bar”:

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

This “raising the bar” is beyond the control of the Transmission Planner and Planning Coordinator and may have significant budget, siting, permitting, and construction impacts on many Transmission Owners. To provide stakeholders with sufficient time to implement changes, a timeframe coincident with the end of the Near-Term Transmission Planning Horizon has been provided

Any entity which cannot eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for these performance elements by that date shall submit a mitigation plan to its Regional Entity outlining the steps it will take to correct the problem. If the entities follow the established ERO procedure for mitigation, it is the intent of the SDT that no penalties will be assessed.

Exhibit C

Proposed Individual TPL Reliability Standards submitted for Approval

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)
2. **Number:** TPL-001-3
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
   - **4.1.** Planning Authority
   - **4.2.** Transmission Planner
5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-3_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-3_R1 and TPL-001-3_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-3_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC
Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised

1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote ‘b’ in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	

Table I. Transmission System Standards – Normal and Emergency Conditions

<table>
<tr><th rowspan="2">Category</th><th>Contingencies</th><th colspan="3">System Limits or Impacts</th></tr>
<tr><th>Initiating Event(s) and Contingency Element(s)</th><th>System Stable and both Thermal and Voltage Limits within Applicable Rating [a]</th><th>Loss of Demand or Curtailed Firm Transfers</th><th>Cascading Outages</th></tr>
<tr><td>A
No Contingencies</td><td>All Facilities in Service</td><td>Yes</td><td>No</td><td>No</td></tr>
<tr><td rowspan="2">B
Event resulting in the loss of a single element.</td><td>Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:
1. Generator
2. Transmission Circuit
3. Transformer
Loss of an Element without a Fault</td><td>Yes
Yes
Yes
Yes</td><td>No [b]
No [b]
No [b]
No [b]</td><td>No
No
No
No</td></tr>
<tr><td>Single Pole Block, Normal Clearing [e]:
4. Single Pole (dc) Line</td><td>Yes</td><td>No [b]</td><td>No</td></tr>
<tr><td rowspan="4">C
Event(s) resulting in the loss of two or more (multiple) elements.</td><td>SLG Fault, with Normal Clearing [e]:
1. Bus Section
2. Breaker (failure or internal Fault)</td><td>Yes
Yes</td><td>Planned/ Controlled [c]
Planned/ Controlled [c]</td><td>No
No</td></tr>
<tr><td>SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]:
3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency</td><td>Yes</td><td>Planned/ Controlled [c]</td><td>No</td></tr>
<tr><td>Bipolar Block, with Normal Clearing [e]:
4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]:
5. Any two circuits of a multiple circuit towerline [f]</td><td>Yes
Yes</td><td>Planned/ Controlled [c]
Planned/ Controlled [c]</td><td>No
No</td></tr>
<tr><td>SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure):
6. Generator
7. Transformer
8. Transmission Circuit
9. Bus Section</td><td>Yes
Yes
Yes
Yes</td><td>Planned/ Controlled [c]
Planned/ Controlled [c]
Planned/ Controlled [c]
Planned/ Controlled [c]</td><td>No
No
No
No</td></tr>
</table>

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of the Contingency, and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 'b' is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Firm Demand interruption under footnote 'b'
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote 'b' (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote 'b' which must include the following:

1. Conditions under which Firm Demand interruption under footnote 'b' would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency

2. Amount of Firm Demand MW to be interrupted with:
    a. The estimated number and type of customers affected
    b. An explanation of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community
3. Estimated frequency of Firm Demand interruption under footnote ‘b’ based on historical performance
4. Expected duration of Firm Demand interruption under footnote ‘b’ based on historical performance
5. Future plans to alleviate the need for Firm Demand interruption under footnote ‘b’
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote ‘b’
8. Assessment of potential overlapping uses of footnote ‘b’ including overlaps with adjacent Transmission Planners and Planning Coordinators

<u>III. Instances for which Regulatory Review of Interruptions of Firm Demand under Footnote ‘b’ is Required</u>

Before a Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote ‘b’ if either:

1. The voltage level of the Contingency is greater than 300 kV
    a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote ‘b’, or
    b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote ‘b’ is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm

Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-~~0.1~~3

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

~~**5.Effective Date:** May 13, 2009~~

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

~~B.~~ B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-~~0~~3_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

~~C.~~ C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-~~0~~3_R1 and TPL-001-~~0~~3_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-~~0~~3_R3.

~~D.~~ D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility
   Compliance Monitor: Regional Reliability Organization.
   Each Compliance Monitor shall report compliance and violations to NERC via the NERC
   Compliance Reporting Process.

   1.2. Compliance Monitoring Period and Reset Time Frame
   Annually

   1.3. Data Retention
   None specified.

   1.4. Additional Compliance Information

2. **Levels of Non-Compliance**

   2.1. Level 1: Not applicable.

   2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

   2.3. Level 3: Not applicable.

   2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

~~E.~~ E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised

1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote ‘b’ in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	**Contingencies**	**System Limits or Impacts**		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of the Contingency, and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

c)—Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 'b' is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Firm Demand interruption under footnote 'b'
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote 'b' (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote 'b' which must include the following:

1. Conditions under which Firm Demand interruption under footnote 'b' would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency

2. Amount of Firm Demand MW to be interrupted with:
    a. The estimated number and type of customers affected
    b. An explanation of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community
3. Estimated frequency of Firm Demand interruption under footnote 'b' based on historical performance
4. Expected duration of Firm Demand interruption under footnote 'b' based on historical performance
5. Future plans to alleviate the need for Firm Demand interruption under footnote 'b'
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 'b'
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote 'b'
8. Assessment of potential overlapping uses of footnote 'b' including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Interruptions of Firm Demand under Footnote 'b' is Required

Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote 'b' if either:

1. The voltage level of the Contingency is greater than 300 kV
    a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote 'b', or
    b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote 'b' is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm

Demand interruption under footnote ‘b’, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption.

A. Introduction

1. **Title:** **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. **Number:** TPL-002-2b

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0a	July 30, 2008	Adopted by NERC Board of Trustees	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Interpretation
0b	September 15, 2011	FERC Order issued approving the Interpretation of R1.3.10 (FERC Order becomes effective October 24, 2011)	Interpretation
1b	April 2010	Revised footnote 'b' pursuant to FERC	Revised

		Order RM06-16-009.	
1b	February 17, 2011	Approved by the Board of Trustees; revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
1b	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
2b	February 7, 2013	Adopted by NERC Board of Trustees. Revised footnote ‘b’.	

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of the Contingency, and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote ‘b’ is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Firm Demand interruption under footnote ‘b’
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote ‘b’ (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote ‘b’ utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote ‘b’ which must include the following:

1. Conditions under which Firm Demand interruption under footnote ‘b’ would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Firm Demand MW to be interrupted with:
    a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community
3. Estimated frequency of Firm Demand interruption under footnote ‘b’ based on historical performance
4. Expected duration of Firm Demand interruption under footnote ‘b’ based on historical performance
5. Future plans to alleviate the need for Firm Demand interruption under footnote ‘b’
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote ‘b’
8. Assessment of potential overlapping uses of footnote ‘b’ including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Interruptions of Firm Demand under Footnote ‘b’ is Required

Before a Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote ‘b’ if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote ‘b’, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote ‘b’ is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote ‘b’, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

A. Introduction

1. **Title:** **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. **Number:** TPL-002-~~0b~~2b

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

~~5. **Effective Date:** Immediately after approval of applicable regulatory authorities.~~

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories~~,~~, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-~~0~~1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-~~0~~1_R1 and TPL-002-~~0~~1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-~~0~~1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0a	July 30, 2008	Adopted by NERC Board of Trustees	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Interpretation

0b	September 15, 2011	FERC Order issued approving the Interpretation of R1.3.10 (FERC Order becomes effective October 24, 2011)	Interpretation
1b	April 2010	Revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised
1b	February 17, 2011	Approved by the Board of Trustees; revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
1b	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
2b	February 7, 2013	Adopted by NERC Board of Trustees. Revised footnote 'b'.	

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	 Yes Yes	 Planned/ Controlled [c] Planned/ Controlled [c]	 No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	 Yes Yes	 Planned/ Controlled [c] Planned/ Controlled [c]	 No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	 No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Gener ator 3. T ransformer 2. T ransmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of the Contingency, and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote ‘b’ is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Firm Demand interruption under footnote ‘b’
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote ‘b’ (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote ‘b’ utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote ‘b’ which must include the following:

1. Conditions under which Firm Demand interruption under footnote ‘b’ would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Firm Demand MW to be interrupted with:
    a. The estimated number and type of customers affected

  b. An explanation of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community
3. Estimated frequency of Firm Demand interruption under footnote ‘b’ based on historical performance
4. Expected duration of Firm Demand interruption under footnote ‘b’ based on historical performance
5. Future plans to alleviate the need for Firm Demand interruption under footnote ‘b’
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote ‘b’
8. Assessment of potential overlapping uses of footnote ‘b’ including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Interruptions of Firm Demand under Footnote ‘b’ is Required

Before a Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote ‘b’ if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote ‘b’, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote ‘b’ is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote ‘b’, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-2a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-2_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

B. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-2_R1 and TPL-003-2_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-2_R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

D. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	July 30, 2008	Adopted by NERC Board of Trustees	
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0a	April 23, 2010	FERC approval of interpretation of TPL-003-0 R1.3.12	Interpretation

1a	February 17, 2011	Approved by the Board of Trustees; revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised (Project 2010-11)
1a	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
2a	February 7, 2013	Adopted by NERC Board of Trustees. Revised footnote 'b'.	

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner’s planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of the Contingency, and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote ‘b’ exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 'b' is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Firm Demand interruption under footnote 'b'
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote 'b' (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote 'b' which must include the following:

1. Conditions under which Firm Demand interruption under footnote 'b' would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Firm Demand MW to be interrupted with:
    a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community
3. Estimated frequency of Firm Demand interruption under footnote ‘b’ based on historical performance
4. Expected duration of Firm Demand interruption under footnote ‘b’ based on historical performance
5. Future plans to alleviate the need for Firm Demand interruption under footnote ‘b’
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote ‘b’
8. Assessment of potential overlapping uses of footnote ‘b’ including overlaps with adjacent Transmission Planners and Planning Coordinators

<u>III. Instances for which Regulatory Review of Interruptions of Firm Demand under Footnote ‘b’ is Required</u>

Before a Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote ‘b’ if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote ‘b’, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote ‘b’ is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote ‘b’, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-~~0a~~2a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

~~5. **Effective Date:** April 23, 2010~~

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

~~B.~~ B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-~~0~~2_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

~~C.~~B. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-~~0~~2_R1 and TPL-003-~~0~~2_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-~~0~~2_R3.

~~D.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

~~E.~~D. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	July 30, 2008	Adopted by NERC Board of Trustees	
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised

0a	April 23, 2010	FERC approval of interpretation of TPL-003-0 R1.3.12	Interpretation
1a	February 17, 2011	Approved by the Board of Trustees; revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised (Project 2010-11)
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Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Gener ator 2. Transmission Circuit 3. T ransformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Gener ator 7. T ransformer 8. T ransmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of the Contingency, and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote ‘b’ is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Firm Demand interruption under footnote ‘b’
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote ‘b’ (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote ‘b’ utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote ‘b’ which must include the following:

1. Conditions under which Firm Demand interruption under footnote ‘b’ would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Firm Demand MW to be interrupted with:
    a. The estimated number and type of customers affected

b. An explanation of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community

3. Estimated frequency of Firm Demand interruption under footnote 'b' based on historical performance
4. Expected duration of Firm Demand interruption under footnote 'b' based on historical performance
5. Future plans to alleviate the need for Firm Demand interruption under footnote 'b'
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 'b'
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote 'b'
8. Assessment of potential overlapping uses of footnote 'b' including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Interruptions of Firm Demand under Footnote 'b' is Required

Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote 'b' if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote 'b', or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote 'b' is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)
2. **Number:** TPL-004-2
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability**:
   - **4.1.** Planning Authority
   - **4.2.** Transmission Planner
5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

B. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-2_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-2_R1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

D. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	February 17, 2011	Approved by the Board of Trustees; revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised (Project 2010-11)
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
2	February 7, 2013	Adopted by NERC Board of Trustees. Revised footnote 'b'.	

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes	 No [b] No [b] No [b]	 No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	 Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c]	 No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	 Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c]	 No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	 No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of the Contingency, and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 'b' is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Firm Demand interruption under footnote 'b'
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote 'b' (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote 'b' which must include the following:

1. Conditions under which Firm Demand interruption under footnote 'b' would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Firm Demand MW to be interrupted with:
    a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community
3. Estimated frequency of Firm Demand interruption under footnote ‘b’ based on historical performance
4. Expected duration of Firm Demand interruption under footnote ‘b’ based on historical performance
5. Future plans to alleviate the need for Firm Demand interruption under footnote ‘b’
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote ‘b’
8. Assessment of potential overlapping uses of footnote ‘b’ including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Interruptions of Firm Demand under Footnote ‘b’ is Required

Before a Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote ‘b’ if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote ‘b’, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote ‘b’ is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote ‘b’, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption.

A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. **Number:** TPL-004- ~~0~~2

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability**:

   4.1. Planning Authority

   4.2. Transmission Planner

~~5. **Effective Date:** April 1, 2005~~

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

~~B.~~ B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

~~C.~~B. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-~~0~~2_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-~~0~~2_R1.

~~D.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

~~E.~~D. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	February 17, 2011	Approved by the Board of Trustees; revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised (Project 2010-11)
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
2	February 7, 2013	Adopted by NERC Board of Trustees. Revised footnote 'b'.	

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating[a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No[b] No[b] No[b] No[b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of the Contingency, and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote ‘b’ is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Firm Demand interruption under footnote ‘b’
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote ‘b’ (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote ‘b’ utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote ‘b’ which must include the following:

1. Conditions under which Firm Demand interruption under footnote ‘b’ would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level

b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency

2. Amount of Firm Demand MW to be interrupted with:
   a. The estimated number and type of customers affected
   b. An explanation of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community
3. Estimated frequency of Firm Demand interruption under footnote ‘b’ based on historical performance
4. Expected duration of Firm Demand interruption under footnote ‘b’ based on historical performance
5. Future plans to alleviate the need for Firm Demand interruption under footnote ‘b’
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote ‘b’
8. Assessment of potential overlapping uses of footnote ‘b’ including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Interruptions of Firm Demand under Footnote ‘b’ is Required

Before a Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote ‘b’ if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote ‘b’, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote ‘b’ is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote ‘b’, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption.

Exhibit D

Implementation Plan for the Individual TPL Reliability Standards

Implementation Plan for Project 2010-11: TPL Table 1 Order

Prerequisite Approvals

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

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed standards.

Compliance with Standards

Standards	**Functions That Must Comply With the Associated Requirements**	
	Transmission Planner	Planning Authority
TPL-001-3: System Performance Under Normal (No Contingency) Conditions (Category A) TPL-002-2b: System Performance Following Loss of a Single Bulk Electric System Element (Category B) TPL-003-2a: System Performance Following Loss of Two or More Bulk Electric System Elements (Category C) TPL-004-2: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)	X X	

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other

requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective.

All other requirements remain in effect as per previous approvals.

Exhibit E

Order No. 672 Criteria

EXHIBIT E

Order No. 672 Criteria

In Order No. 672,[1] the Commission identified a number of criteria that it will use to analyze Reliability Standards proposed for approval to ensure that a proposed Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors, and explains how the Footnote and the Proposed TPL Standards meet or exceed the criteria:[2]

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[3]

The proposed Footnote is designed to provide specificity and consistency in order to allow for planned load shed for single Contingencies. The Commission found that the existing footnote is ambiguous and could result in inconsistent application, because, among other reasons, there were no limitations on maximum usage. The proposed Footnote establishes an open and transparent process with affected stakeholders and

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006) (together, "Order 672")).

[2] Capitalized terms used but not defined in this Attachment A are intended to have the same meaning given to such terms in the Petition, the Proposed Standards or the *Glossary of Terms Used in NERC Reliability Standards*, available at: http://www.nerc.com/files/Glossary_of_Terms.pdf.

[3] *Id.* at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of Section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

Id. at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

regulators with established criteria that must be met in order to plan for the use of the Footnote. The Footnote establishes, for U.S.-registered entities, quantitative limits on the maximum amounts of load that can be shed, with the limits derived from the results of the Data Request (the results of which can be found in **Exhibit F**). The result is a consistent, documented process with firm limitations on use of the Footnote. The technical analysis justifying the use of the Footnote in specific circumstances will be available to all affected stakeholders in an open forum where all alternatives can be discussed and resolved. ERO oversight will assure that there are no Adverse Reliability Impacts on the Bulk Electric System from the planned actions.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the Bulk-Power System, and must be clear and unambiguous as to what is required and who is required to comply.[4]

The proposed Footnote is applicable to Planning Coordinators and Transmission Planners. Planning Coordinators and Transmission Planners are users, owners, or operators of the Bulk Electric System. The proposed Footnote achieves the stated reliability goal of clearly stating what is required and who is required to comply. Attachment 1 to the Footnote details the process that is to be followed, the information requirements to justify the proposed application of the Footnote, and the timing involved in the process steps. The standard states who the applicable entities are, and Attachment 1 reiterates the roles and responsibilities of the responsible entities at each step.

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[4] *Id.* at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

Id. at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation. [5]

Each primary requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines. The Consolidated TPL Standard does not modify the proposed VRFs and VSLs that were included in the petition with the Commission for approval on October 19, 2011. None of the previously approved VRFs and VSLs for the Individual TPL Standards have been altered or changed in any way.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner. [6]

The proposed Footnote is clear in identifying the required performance and the responsible entity. The proposed Footnote identifies clear and objective criteria so that that the Footnote can be enforced in a consistent and non-preferential manner. The Footnote is unambiguous with respect to the expectations of applicable entities. The proposed Footnote establishes definitive steps that must be followed as well as clear, quantitative criteria for planned use of the Footnote.

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[5] *Id.* at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

[6] *Id.* at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[7]

The proposed Footnote helps the industry achieve the goal of effective and efficient system planning, while taking into account factors such as implementation, cost, and geographic differences and system design. The stakeholder process outlined in Attachment 1 provides that responsible planning entities must show the alternatives that were considered in order to avoid potential problems, and provide the rationale for the alternative selected. Factors such as implementation cost and unique system characteristics would be taken into account and the planning entity can demonstrate to stakeholders why a particular solution is being proposed. Thus, an entity can appropriately weigh all the relevant factors and make them clear in an open and transparent forum.

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[7] *Id.* at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

6. Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect Bulk Electric System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[8]

The proposed Footnote does not aim at the "lowest common denominator." The Footnote applies equally to all Planning Coordinators and Transmission Planners, without differentiation based on size or cost. The quantitative criteria proposed in the Footnote are derived from the results of the Data Request and set out reasonable, technically-sound limits that define how a planning entity may plan to shed non-consequential load in a single Contingency situation. The proposed limits cover variables that were not specified in the Current TPL Standards and represent new and significant constraints for planning entities.

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[8] *Id.* at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although FERC will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

7. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[9]

The requirements in the proposed Footnote apply throughout North America, with an exception for non-U.S. registered entities. The Footnote allows for the amount of planned non-consequential load loss for a non-U.S. registered entity to be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-U.S. jurisdiction. This "non-U.S." exception is warranted, because the limitations on the amount of load that can be planned to be shed under the Footnote are, by legislation, the sole province of the local regulatory authorities in those countries.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[10]

The proposed Footnote enhances the operation and reliability of the BES, without constraint on competition or transmission capability. The Footnote does not differentiate

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[9] *Id.* at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

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

among entities, and applies equally to all Planning Coordinators and Transmission Planners. The Footnote presents a consistent approach to be followed across the North American continent with appropriate emphasis on reliability.

9. The implementation time for the proposed Reliability Standard is reasonable.[11]

The proposed Implementation Plans are reasonable and unchanged from proposed Implementation Plans submitted previously to the Commission. The Implementation Plans weigh carefully the significant nature of new requirements against the need for responsible entities to gear up to meet those requirements. Accordingly, the proposed effective dates represent a reasonable time frame to allow all entities to adequately prepare for compliance with the new, more stringent requirements.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[12]

The Footnote and the Proposed TPL Standards were developed in accordance with NERC's Commission-approved, ANSI-accredited processes for developing and approving Reliability Standards. As more fully described in Section IV of the petition

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[11] *Id.* at P 333. In considering whether a proposed Reliability Standard is just and reasonable, FERC will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

[12] *Id.* at P 334 ("Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.").

(Summary of the Reliability Standard Development Proceedings) and **Exhibit G** (Summary of Proposed TPL Standards Development Authorization, Posting, and Balloting History), these processes included, among other things, multiple comment; pre-ballot review; and balloting periods, conducted pursuant to an aggressive schedule that spanned a period of nearly seven months. All Drafting Team meetings were properly noticed and open to the public. Stakeholders were involved during the comment periods. The initial and recirculation ballots achieved the required quorum and ballot pool thresholds. Specific details concerning these processes, including a complete development history and a record of all stakeholder comments received, have been included as **Exhibit I**.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[13]

NERC has identified no competing public interests regarding the request for approval of the Footnote and Proposed TPL Standards. No comments were received that indicated that the Footnote or Proposed TPL Standards conflict with other vital public interests.

[13] *Id.* at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

12. Proposed Reliability Standards must consider any other appropriate factors.[14]

No other factors for FERC's consideration were identified in the development of the proposed Footnote.

13. Proposed Reliability Standard must not conflict with prior FERC Rules or Orders.

The Footnote and Proposed TPL Standards do not conflict with prior Commission Rules or Orders. To the contrary, they respond to Commission concerns most recently articulated in Order No. 762 and the TPL NOPR.

[14] *Id.* at P 337. In considering whether a proposed Reliability Standard is just and reasonable, the Commission may consider any other factors it deems appropriate for determining if the proposed Reliability Standard is just and reasonable, not unduly discriminatory or preferential, and in the public interest. The ERO may, if it chooses, propose other such general factors in its application and may propose additional specific factors for consideration with a particular proposed Reliability Standard.

Exhibit F

Results of Section 1600 Data Request

Proposed Request for Data or Information Order No. 762 Transmission System Performance Following Loss of a Single Bulk Electric System Element

NERC posted the proposed data request in accordance with the requirements of Section 1606 of the NERC Rules of Procedure for public comment. The twenty-one (21) day comment period ran from June 19 through July 9, 2012. NERC provided this proposed data request to FERC for information on May 23, 2012, as required by Section 1602 of the NERC Rules of Procedure. NERC presented this proposed data request, revised as appropriate in light of the comments received, to the NERC Board of Trustees for approval, as required by Section 1602 of the NERC Rules of Procedure on July 26, 2012. The NERC Board of Trustees approved the revised data request and it has now been issued and has become mandatory.

The purpose of this data request is to solicit data and information from each registered Transmission Planner in the United States and Canada[1] in order to provide information identifying the specific instances of any planned interruptions of Firm Demand under footnote b and how frequently the provision has been used. This data will be used by the Standards Drafting Team to guide its deliberations in areas where threshold values are suggested in the revised footnote b. NERC will also share the data received in response to this data request with FERC.

The data request was posted publicly for 30 days, from July 31, 2012 through August 30, 2012. Transmission Planners were asked to provide data or information through a special electronic comment form. There were 158 responses submitted, with some responses representing multiple entities, representing 7 of the 10 Industry Segments as shown in the table on the following pages.

All data requests and information submitted may be reviewed in their original format on the standard's [project page](#).

If you feel that your submitted data has been overlooked, please let us know immediately. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[2]

[1] In the United States responding to this data request is mandatory. NERC strongly encourages Canadian entities to respond to this data request to ensure the completeness of the data collected.

[2] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
1.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				
2.	Group	Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				
3.	Group	Jennifer Eckels	Colorado Springs Utilities	X		X		X	X				
4.	Group	Sunitha Kothapalli	Puget Sound Energy	X				X					
5.	Group	Jason Shook	East Texas Electric Cooperative, Inc.	X		X	X						
6.	Group	Delyn Kilpack	LG&E and KU Services	X		X		X	X				
7.	Individual	Terry Torgerson	Dairyland Power Cooperative	X		X		X					
8.	Individual	JANET SMITH	ARIZONA PUBLIC SERVICE COMPANY	X		X		X	X				
9.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
10.	Individual	Lonnie Lindekugel	Southwest Power Pool RTO		X								

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
11.	Individual	Tim Ponseti, VP	TVA Transmission Reliability Engineering & Controls	X								X	
12.	Individual	Renee Davidson	South Texas Electric Cooperative, Inc.										
13.	Individual	Brian Whalen	Nevada Power Company - NCR05261	X		X		X					
14.	Individual	Brian Whalen	Sierra Pacific Power Company - NCR05390	X		X		X					
15.	Individual	Terry Harbour	MidAmerican Energy	X		X		X	X				
16.	Individual	Esteban Martinez	Turlock Irrigation District	X		X	X	X	X				
17.	Individual	John Burnett	Los Angeles Department of Water and Power	X		X		X					
18.	Individual	Theresa Allard	Minnkota Power Cooperative, Inc.	X		X							
19.	Individual	Aaron Staley	City of Vero Beach	X									
20.	Individual	Bryant D. Williamson	Memphis Light, Gas and Water	X									
21.	Individual	Richard Bachmeier	Gainesville Regional Utilities	X		X		X				X	
22.	Individual	Michael Jones	National Grid	X		X							
23.	Individual	William Berry	OMU			X							
24.	Individual	(CHPD) Public Utility District No. 1 of Chelan County	Public Utility District No. 1 of Chelan County (CHPD)	X		X		X	X			X	
25.	Individual	Daniela Hammons	CenterPoint Energy Houston Electric, LLC	X									
26.	Individual	Raymond Andrew Foster	Nashville Electric Service	X									
27.	Individual	Scott Bos	Muscatine Power and Water	X		X		X	X				
28.	Individual	Gini Ingram	Lafayette Utilities System			X							
29.	Individual	Lou Magyar	Hoosier Energy REC, Inc.	X		X							
30.	Individual	Eric Olson	Transmission Agency of Northern California	X									
31.	Individual	D Roberts	SBEC	X		X							
32.	Individual	Scott Waples	Avista Corporation	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
33.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X	X				
34.	Individual	Tracey Stewart	Southwestern Power Administration	X								X	
35.	Individual	Western Area Power Administration	Upper Great Plains Region	X		X			X				
36.	Individual	Richard E Biggerstaff	Sharyland Utilities, L.P.										
37.	Individual	Greg Keller	Florida Power & Light	X		X		X					
38.	Individual	Angela P Gaines	Portland General Electric Company	X		X		X	X				
39.	Individual	Jose H Escamilla	CPS Energy	X		X		X					
40.	Individual	Rob Collins	Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana Inc.			X			X				
41.	Individual	Laurie Williams	Public Service Company of New Mexico (PNM)	X		X		X	X				
42.	Individual	Rakesh Sharma	JEA	X		X		X					
43.	Individual	Tony Gott	Associated Electric Cooperative, Inc.	X				X				X	
44.	Individual	Arun Sethi	Western Area Power Administration - Sierra Nevada Region										
45.	Individual	Shari Heino	Brazos Electric Power Cooperative, Inc.	X				X					
46.	Individual	John Pearson	ISO New England		X								
47.	Individual	Bob Easton	WAPA-RMR	X									
48.	Individual	Patrick Harwood	Western Area Power Administration Desert Southwest Region	X		X							
49.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
50.	Individual	Jonathan Appelbaum	The United Illuminating Company	X									
51.	Individual	Thomas E King Jr	Wolverine Power Supply Cooperative, Inc	X		X							
52.	Individual	Larry Watt	Lakeland Electric	X		X		X	X				
53.	Individual	Paul Haase	Seattle City Light	X		X	X	X	X				
54.	Individual	Wryan J. Feil	Northeast Utilities	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
55.	Individual	Franklin Lu	Public Utility District No. 1 of Snohomish County	X		X	X	X	X				
56.	Individual	Will Franklin	Public Service Company of Colorado	X		X		X	X				
57.	Individual	Jonathan Fidrych	Tri-State G & T Association, Inc.	X		X		X					
58.	Individual	Edward O'Brien	Modesto Irrigation District			X	X		X				
59.	Individual	Kevin Lyons	Central Iowa Power Cooperative										
60.	Individual	John Allen	City Utilities of Springfield, MO	X			X						
61.	Individual	Randi Nyholm	Minnesota Power	X									
62.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				
63.	Individual	Tiffany Lake	Westar Energy, Inc.	X		X		X	X				
64.	Individual	Michael Haff	Seminole Electric Cooperative, Inc.			X	X	X	X				
65.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
66.	Individual	Gary Trent	Tucson Electric Power Company	X									
67.	Individual	Darrin Adams	East Kentucky Power Cooperative	X		X		X					
68.	Individual	Greg Keller	Lone Star Transmission, LLC	X									
69.	Individual	Greg Keller	Horse Hollow Generation Tie, LLC.	X									
70.	Individual	Kirit Shah	Ameren	X		X		X	X				
71.	Individual	Martyn Turner	LCRA Transmission Services Corporation	X									
72.	Individual	James Tucker	Deseret Power	X		X		X					
73.	Individual	Debbie Manning	Bangor Hydro Electric Company	X		X							
74.	Individual	Terri Pyle	Oklahoma Gas & Electric	X		X		X					
75.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
76.	Individual	Harold Wyble	Kansas City Power & Light	X		X		X	X				
77.	Individual	Jennifer Wright	San Diego Gas & Electric	X		X		X					
78.	Individual	Alice Ireland	Southwestern Public Service Co, an Xcel Energy company	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
79.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
80.	Individual	Michelle Corley	Cleco Corporation	X		X		X	X				
81.	Individual	Joe Knight	Great River Energy	X		X		X	X				
82.	Individual	Frank Gaffney	Florida Municipal Power Agency			X	X	X	X				
83.	Individual	Jim Kelley	PowerSouth Energy Cooperative	X				X					
84.	Individual	Donald Bauer	NorthWestern Corporation	X		X		X					
85.	Individual	chris diebold	city of tallahassee	X		X		X					
86.	Individual	James Peterson	South Carolina Public Service Authority	X		X		X					
87.	Individual	Milorad Papic	Idaho Power Co.	X		X							
88.	Individual	Gregory Campoli	New York Independent System Operator		X								
89.	Individual	Jeremy Brownrigg	Platte River Power Authority	X		X		X				X	
90.	Individual	Jan Horbaczewski	Texas Municipal Power Agency	X									
91.	Individual	Shawndra Green	Bryan Texas Utilities	X		X		X					
92.	Individual	Thad Ness	American Electric Power	X		X		X					
93.	Individual	David A Macey	City of Independence Department of Power & Light	X		X							
94.	Individual	Brad Hofferkamp	PJM	X	X	X		X					
95.	Individual	Don Schmit	Nebraska Public Power District										
96.	Individual	Bob Case	Black Hills Corporation	X		X	X	X	X				
97.	Individual	Ruth Kloecker	ITC Holdings	X									
98.	Individual	Raiza Calderon	Tampa Electric Company	X				X					
99.	Individual	Boris Tumarin	Southwest Transmission Cooperatives, inc	X									
100.	Individual	Chris Bradley	Big Rivers Electric Corporation	X		X		X					
101.	Individual	Alan Wilson	SMEPA	X		X	X	X	X				
102.	Individual	Oliver Burke	Entergy Services, Inc.	X		X		X	X				
103.	Individual	Eric Ruskamp	Lincoln Electric System	X		X		X	X				

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
104.	Individual	Marco Rios	Pacific Gas and Electric Company	X		X		X					
105.	Individual	Jeff Jones	Southern Illinois Power Cooperative	X		X		X					
106.	Individual	David Rudolph	Basin Electric Power Cooperative (BEPC)	X		X		X					
107.	Individual	Keira Kazmerski	Northern States Power Company, an Xcel Energy company	X		X		X	X				
108.	Individual	Brenton Lopez	Salt River Project	X		X		X	X				
109.	Individual	David Baker	Bandera Electric Cooperative, Inc.	X		X	X						
110.	Individual	Lindsay Shepard	Sunflower Electric Power Corporation	X		X		X					
111.	Individual	Pablo Onate	El Paso Electric Co.										
112.	Individual	Dean Ahlsten	Eugene Water & Electric Board										
113.	Individual		GCPUD										
114.	Individual	Gerry Nunan	Bluebonnet Electric Cooperative										
115.	Individual	DeWayne Todd	Alcoa Power Generating Co.										
116.	Individual	David Grubbs	City of Garland										
117.	Individual	Mike Pullen	Electric Energy Inc.										
118.	Individual	Galen Gillum	City of Denton										
119.	Individual	Tyler Baxter	Corn Belt Power										
120.	Individual	Stacey Englemann	City of College Station										
121.	Individual	Tim Lyons	Owensboro Municipal										
122.	Individual	John Delucca	Lee County										
123.	Individual	Mike Stafford	Grand River Dam Authority										
124.	Individual	Frank Owens	Cross Texas Transmission										
125.	Individual	Steve Rose	City Water Light & Power										
126.	Individual	Julius Horvath	Wind Energy of Texas										
127.	Individual	Sandra Shaffer	Pacificorp										
128.	Individual	Nathan McNeil	Midwest Energy										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
129.	Individual	Archie Lopez	Pedernales Electric Co-op										
130.	Individual	Mike Holtsclaw	Indianapolis Power & Light										
131.	Individual	Rick Luckadoo	Rochester Public Utilities										
132.	Individual	Greg Baumbach	New Braunfels Utilities										
133.	Individual	Caitlin Hojnacki	City of Lansing										
134.	Individual	Zandalio Martinez	Brownsville PUB										
135.	Individual	Joseph Turano	Central Maine										
136.	Individual	Joseph Turano	Maine Electric										
137.	Individual	Kim Moulton	Vermont Transco										
138.	Individual	John Robertson	NSTAR										
139.	Individual	Amanda Underwood	Omaha PPD										
140.	Individual	Daryll Curtis	Oncor										
141.	Individual	Lee Kittelson	Otter Tail Power										
142.	Individual	Rich Dragonajtys	Merced Irrigation District										
143.	Individual	Nathan Smith	SCE										
144.	Individual	Caleb Muckala	Western Farmers										
145.	Individual	Rich Koch	Southern Minnesota										
146.	Individual	David Rusley	Cedar Falls										
147.	Individual	Ron Wyble	Columbia Water & Light										
148.	Individual	Bob Mattey	Ohio Valley										
149.	Individual	Rex McDaniel	Texas New Mexico										
150.	Individual	Nelson Nease	Guadeloupe Valley										
151.	Individual	Bob Adam	Kansas City BPU										
152.	Individual	Dennis Minton	Florida Keys										
153.	Individual	Jason Snodgrass	GTC										
154.	Individual	Hank LuBean	Douglas County PUD										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
155.	Individual	Fred Meyer	Empire District										
156.	Individual	Aaron Staley	Orlando Utilities Commission										
157.	Individual	Robert Fox	NIPSCO										
158.	Individual	Aaron Staley	Orlando PUC										

1. For which NERC Compliance Registry (NCR) numbers are you completing this Data Request?

Organization	Question 1 Comment
1. Tri-State G & T Association, Inc.	NCR10030
2. City of Tallahassee	NCR00073
3. Dairyland Power Cooperative	NCR00762
4. Wolverine Power Supply Cooperative, Inc	NCR00954
5. Lincoln Electric System	NCR01001
6. Nebraska Public Power District	NCR01018
7. City of Independence Department of Power & Light	NCR01072
8. Southwest Power Pool RTO	NCR01143
9. TVA Transmission Reliability Engineering & Controls	NCR01151
10. East Kentucky Power Cooperative	NCR01225
11. OMU	NCR01290
12. Bryan Texas Utilities	NCR04022
13. SBEC	NCR04118
14. Sharyland Utilities, L.P.	NCR04119

Organization	Question 1 Comment
15. Colorado Springs Utilities	NCR05106
16. Public Utility District No. 1 of Chelan County (CHPD)	NCR05338
17. Western Area Power Administration Desert Southwest Region	NCR05461
18. WAPA-RMR	NCR05464
19. Western Area Power Administration - Sierra Nevada Region	NCR05465
20. Public Service Company of Colorado	NCR05521
21. The United Illuminating Company	NCR07222
22. South Carolina Electric and Gas	NCR00915
23. American Transmission Company	NCR #685
24. PowerSouth Energy Cooperative	NCR 10203
25. Florida Municipal Power Agency	NCR00022
26. Florida Power & Light	NCR00024
27. Gainesville Regional Utilities	NCR00032
28. JEA	NCR00040

Organization	Question 1 Comment
29. Lakeland Electric	NCR00044
30. Seminole Electric Cooperative, Inc.	NCR00068
31. Tampa Electric Company	NCR00074
32. City of Vero Beach	NCR00079
33. Basin Electric Power Cooperative (BEPC)	NCR00102, NCR05023
34. Westar Energy, Inc.	NCR00658
35. Minnesota Power	NCR00674
36. Hoosier Energy REC, Inc.	NCR00794
37. ITC Holdings	NCR00820, NCR00803, NCR10192, NCR10400
38. MidAmerican Energy	NCR00824
39. Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana Inc.	NCR00917
40. Muscatine Power and Water	NCR00967
41. Central Iowa Power Cooperative	NCR00970
42. Great River Energy	NCR00992
43. Minnkota Power Cooperative, Inc.	NCR01013

Organization	Question 1 Comment
44. Northern States Power Company, an Xcel Energy company	NCR01020 (Northern States Power Company)
45. Upper Great Plains Region	NCR01036 & NCR05467
46. American Electric Power	NCR01056, NCR04006, NCR10211
47. Kansas City Power & Light	NCR01058 NCR01107
48. City Utilities of Springfield, MO	NCR01081
49. Cleco Corporation	NCR01083
50. Lafayette Utilities System	NCR01114
51. Oklahoma Gas & Electric	NCR01130
52. Southwestern Power Administration	NCR01144
53. Southwestern Public Service Co, an Xcel Energy company	NCR01145
54. Sunflower Electric Power Corporation	NCR01148
55. Ameren	NCR01175
56. Associated Electric Cooperative, Inc.	NCR01177
57. Big Rivers Electric Corporation	NCR01180

Organization	Question 1 Comment
58. Entergy Services, Inc.	NCR01234
59. Duke Energy	NCR01298, NCR00761, NCR01219 and NCR00063
60. East Texas Electric Cooperative, Inc.	NCR01307, NCR01227, NCR01124, NCR01342
61. South Carolina Public Service Authority	NCR01312
62. SMEPA	NCR01315
63. Southern Company	NCR01320, NCR01278
64. Southern Illinois Power Cooperative	NCR01321
65. PJM	NCR02602,NCR00682,NCR00686,NCR00688,NCR00689,NCR00712,NCR08013,NCR00752,NCR00761,NCR00762,NCR00251,NCR00806,NCR10376,NCR00821,NCR00130,NCR08026,NCR00872,
66. Bandera Electric Cooperative, Inc.	NCR04008
67. Brazos Electric Power Cooperative, Inc.	NCR04015
68. CenterPoint Energy Houston Electric, LLC	NCR04028
69. City of Austin dba Austin Energy	NCR04029
70. CPS Energy	NCR04037
71. LCRA Transmission Services Corporation	NCR04091

Organization	Question 1 Comment
72. South Texas Electric Cooperative, Inc.	NCR04124
73. Texas Municipal Power Agency	NCR-04141
74. ARIZONA PUBLIC SERVICE COMPANY	NCR05016
75. Black Hills Corporation	NCR05030 and NCR00089
76. Bonneville Power Administration	NCR05032
77. Tacoma Power	NCR05097
78. Deseret Power	NCR05126,NCR05127
79. Idaho Power Co.	NCR05191
80. Imperial Irrigation District (IID)	NCR05195
81. Avista Corporation	NCR0520
82. Los Angeles Department of Water and Power	NCR05223
83. Modesto Irrigation District	NCR05244
84. Nevada Power Company - NCR05261	NCR05261
85. NorthWestern Corporation	NCR05282
86. Pacific Gas and Electric Company	NCR05299

Organization	Question 1 Comment
87. Platte River Power Authority	NCR05321
88. Portland General Electric Company	NCR05325
89. Public Service Company of New Mexico (PNM)	NCR05333
90. Public Utility District No. 1 of Snohomish County	NCR05335
91. Puget Sound Energy	NCR05344
92. Sacramento Municipal Utility District	NCR05368
93. Salt River Project	NCR05372
94. San Diego Gas & Electric	NCR05377
95. Seattle City Light	NCR05382
96. Sierra Pacific Power Company - NCR05390	NCR05390
97. Southwest Transmission Cooperatives, inc	NCR05402
98. Transmission Agency of Northern California	NCR05430
99. Tucson Electric Power Company	NCR05434
100. Turlock Irrigation District	NCR05435
101. Bangor Hydro Electric Company	NCR07013

Organization	Question 1 Comment
102. ISO New England	NCR07124
103. New York Independent System Operator	NCR07160
104. Northeast Utilities	NCR07176
105. Horse Hollow Generation Tie, LLC.	NCR10392
106. Lone Star Transmission, LLC	NCR11076
107. Nashville Electric Service	NCR11077
108. National Grid	NCR11171 National Grid USA
109. LG&E and KU Services	NRC01223
110. Memphis Light, Gas and Water	NCR11066
111. El Paso Electric Company	NCR05140
112. GCPUD	NCR05342
113. Eugene Water & Electric Board	NCR05153
114. Bluebonnet Electric Cooperative	NCR0413
115. Alcoa Power Generating Co.	NCR01168 & NCR01169
116. City of Garland	NCR04033
117. Electric Energy Inc.	NCR01230

Organization	Question 1 Comment
118. Wind Energy of Texas	NCR11074
119. City of Denton	NCR04049
120. Corn Belt Power	NCR00977
121. City of College Station	NCR04032
122. Owensboro Municipal	NCR01290
123. Lee County	NCR00045
124. Grand River Dam Authority	NCR01101
125. Cross Texas Transmission	NCR11114
126. City Water Light & Power	NCR01328
127. Pacificorp	NCR05304
128. Midwest Energy	NCR01118
129. Pedernales Electric Co-op	NCR04111
130. Indianapolis Power & Light	NCR00798
131. Rochester Public Utilities	NCR01027
132. New Braunfels Utilities	NCR04101
133. City of Lansing	NCR00718
134. Brownsville PUB	NCR04018

Organization	Question 1 Comment
135. Central Maine	NCR07029
136. Maine Electric	NCR07134
137. Vermont Transco	NCR07228
138. NSTAR	NCR07180
139. Omaha PPD	NCR00860
140. Oncor	NCR04109
141. New Brunswick	NCR10024
142. Otter Tail Power	NCR01023
143. Merced Irrigation District	NCR05234
144. SCE	NCR05398
145. Western Farmers	NCR 01160
146. Southern Minnesota	NCR01030
147. Cedar Falls	NCR00969
148. Columbia Water & Light	NCR 01196
149. Ohio Valley	NCR00857
150. Texas New Mexico	NCR04143
151. Guadalupe Valley	NCR04079

Organization	Question 1 Comment
152. Kansas City BPU	NCR01061
153. Florida Keys	NCR00021
154. GTC	NCR01249
155. Douglas County PUD	NCR05343
156. Empire District	NCR01155
157. Orlando Utilities	NCR00057
158. NIPSCO	NCR02611

2. **Does the Planning Assessment for the interconnected transmission system for which you have planning responsibility include any instances of planned interruption of Firm Demand to address BES performance requirements following a single contingency (i.e., any use of "planned or controlled interruption of supply") as described in footnote "b" of the TPL-002-0b Reliability Standard for the last 3 completed Planning Assessments?**

Summary Consideration: The overwhelming majority of respondents do not utilize footnote 'b' in their planning process. There were only 18 entities indicating any utilization of footnote 'b' in their planning process.

Table removed for reasons of confidentiality.

3. If the answer to Question 2 is yes, please identify:

a. Indicate the year of the Planning Assessment for which you are reporting.
b. Each unique instance within the applicable Planning Assessment in which planned interruption of Firm Demand has been used as a strategy to address BES performance requirements following a single contingency, including the size (in MW) of the planned interruption of Firm Demand, and the operating voltage level (kV) and description of each contingency.
c. The size (in MW) of the each instance of planned interruption of Firm Demand following a single contingency within the applicable Planning Assessment.
d. The estimated cost (if known) of reinforcements needed to eliminate the need for each instance of planned interruption of Firm Demand in the applicable Planning Assessment following a single contingency.
e. The year (if known) in which reinforcements are planned to eliminate the need for each instance of planned interruption of Firm Demand in the applicable Planning Assessment following a single contingency.
f. What year was the earliest instance of planned interruption of Firm Demand following a single contingency that is still included in the applicable Planning Assessment identified?
g. What year was the most recent instance of planned interruption of Firm Demand following a single contingency that is still included in the applicable Planning Assessment identified?

Organization	Question 3a Comment
A	a. 2011 b. In 2013 winter season: I) 8.4 MW, 230 kV, Contingency 230 kV; II) 8.4 MW, 230 kV, Contingency transformer 230/138 kV; III) 43 MW, 230 kV, Contingency 230 kV; IV) 14 MW, 115 kV, Contingency 115 kV. c. See answer b. d. Unknown

Organization	Question 3a Comment
	e. Unknown f. 2013 Winter case - In 2011 Assessment g. same as answer to f
B	a. 2011 b. Contingency: Loss of the 230 kV line. The size of the planned interruption of Firm Demand is determined by the amount of load above 65 MW. Operating voltage level: 115 kV. c. The size of planned interruption of Firm Demand is determined by the size of the load during the time of the contingency. For loss of the 230 kV line, load is limited to 65 MW. (This represents a 69 MW load drop.) d. Unknown e. Unknown f. 1998 g. 1998
C	a. 2011 b. The planned outage of certain 100 kV facilities in the area that feed a 50 kV system including load can require a 10 - 12 MW curtailment of the load to avoid low voltage problems on the area 100 and 50 kV systems. Unplanned outages may cause the shedding of a similar amount of load through the customer's under voltage relay protection, but voltages within tolerances result after the load shed. Note: C has not intentionally chosen curtailment of firm demand as a form of mitigation for system problems such as this. c. Again, 10 - 12 MW d. We are planning a new transmission line into this area, with associated substation work. Estimated cost $M

Organization	Question 3a Comment
	e. f. 2006 (possibly earlier) g.
D	a. 2012 b. 1. interruption of 2.5 MW, 161-kV, contingency of tap line section 2. interruption of 4.1 MW, 161-kV, contingency of 3. interruption of 4.3 MW, 161-kV, contingency of c. See response to question 3b. d. Each of the three events described in question 3b would minimally require a capacitor bank at estimated cost of $. However another option for each of these three contingencies could be a 7 mile (average of three events) transmission line along with a 161-kV switching station. The total cost for including both line and station costs could exceed $ million to fix each contingency. e. 1. 2. 3. f. 2010 (earliest of past 3 completed Planning Assessments) g. 2012
E	a. b. The 138 kV line has two tapped loads. The total load is about 30 MW. The breakers are at. Thus whenever the line trips for a fault or other reason, the load is interrupted. This design has been in place since it was constructed in 1985. c. in all assessments about 30 MW d. $ million, a second line would be required.

Organization	Question 3a Comment
	e. Not currently planned f. The line with the load taps was built in 1985 and has not been changed. g. 2012
Comment: This data was not considered as the respondent provided data for tapped or Consequential Load.	
F	a. 2009 and 2010 b. 2009 Assessment: #1.Loss of 138 kV;10 MW Planned Interruption of Firm Demand (Summer, 20). #2.Loss of 138 kV; 5 MW Planned Interruption of Firm Demand (Summer, 20). #3 Loss of 230 kV; (a) 30 MW Planned Interruption of Firm Demand (Winter), (b) 25 MW Planned Interruption of Firm Demand (Summer), (c) 40 MW Planned Interruption of Firm Demand (Winter). #4.Loss of 138 kV; 10 MW Planned Interruption of Firm Demand (Summer). 2010 Assessment: #1.Loss of 138 kV; (a) 20 MW Planned Interruption of Firm Demand (Winter). (b) 25 MW Planned Interruption of Firm Demand (Winter). c. 2009 Assessment: #1. 10 MW, #2. 5 MW #3. (a) 30 MW, (b) 25 MW, (c) 40 MW, #4. 10 MW. 2010 Assessment: #1(a) 20 MW, (b) 25 MW. d. 2009 Assessment: #4. $

Organization	Question 3a Comment
	e. 2009 Assessment: #4. 2011 f. 2009 Assessment: #1. 20 Summer, #2. 20 Summer, #3. (a) 20 Winter, (b) 20 Summer, (c) 20 Winter, #4. 20 Summer. 2010 Assessment: #1(a) 20 Winter, (b) 20 Winter. g. See response above for 3f.
G	a. 2009, 2010, 2011 b. 30MW, 115kV, loss of 115kV line segment. Operating Guide is used to restore load until project is completed in 20. c. 30MW d. $ e. 6/1/2013 f. 2009 g. 2011
H	a. 2009,2010, 2011 b. The 2009 Planning Assessment recommended undervoltage load shedding of firm demand served from the 115 kV switching station following a single contingency. The interruption of firm demand was implemented as an interim measure pending completion of an additional transmission circuit. The area system had recently been acquired. As acquired, the system was served by two 115 kV transmission lines. The addition of a 3rd 115 kV transmission line and voltage support were identified in previous Planning Assessments to bring the system in the contingency performance criteria. The recommendation for undervoltage

Organization	Question 3a Comment
	load shedding was included in the 2009 Planning Assessment due to delays experienced in completing the third transmission line. The contingency resulting in voltage criteria violations was loss of the 115 kV line. The undervoltage load shedding scheme had the potential to shed up to 26 MW depending on the load level. The 2010 Planning Assessment identified the need to extend undervoltage load shedding in the area through 2011. The issues identified in the 2009 Planning Assessment were aggravated by failure of a 345/115 kV transformer. However, the 2010 Planning Assessment indicated that the replacement of the transformer and completion of the 3rd 115 kV line would not mitigate the need to shed firm load for a single contingency. Additional voltage support would be needed to mitigate load shedding due to a single contingency. The amount of load subject to undervoltage load shedding by the 2011 summer peak was 31 MW. The 2011 Planning Assessment indentified the need to extend the undervoltage load shedding in the area through 2011 due to a delay in installing additional voltage support. The amount of load subject to undervoltage load shedding by the 2012 summer peak remained at 31 MW. c. The 2009 assessment identified up to 26 MW for 2010 summer peak forecast area load. The 2010 assessment identified up to 31 MW of the 2011 summer peak forecast area load. The 2011 assessment identified up to 31 MW of the 2012 summer peak forecast area load. d. The instance identified that impacted both the 2009 and 2010 assessments was eliminated with the addition of third transmission line. Additional voltage support is also required to eliminate the need for planned interruption at a

Organization	Question 3a Comment
	projected cost of $ million. e. The third transmission line into the area and replacement of the transformer were completed in 20. The required voltage support is planned to be installed in 20. f. 2010 g. 2012
I	a. 2010 and 2011 b. The following are examples where used planned interruption of firm demand to address BES performance requirements in previous planning studies. Note: When I identifies a reliability issue in the outer years, it develops plans to mitigate the issue and does not use load curtailment as sole long term mitigation to reliability issues. However, in the near term, if reliability issues occur and cannot be mitigated in a timely manner through system reinforcement, then Load curtailment is exercised as a potential option to mitigate until a permanent solution is developed and acted upon. See tables at end of report for details. c. Shown in previous tables. d. Unknown e. Example 1: 115 kV line contraction schedule to be completed by the end of . Example 2: 115 kV line contraction schedule to be completed by the end of . Example 3: 115 kV contraction schedule to be completed by the end of . Example 4: 115 kV line contraction schedule to be completed by the end of . f. 2012 g. 2012

Organization	Question 3a Comment
J	a. 2010 Assessment 2011 and 2012 interim assessments. b. J has two instances, in the transmission area, where footnote b of TPL-002-0b could be considered to be addressing a performance requirement following a single contingency. The interruption is only considered part of a temporary mitigation plan until a project to address the situation is completed. The two instances involve the overloading of either of two 115kV lines where 20MW is the planned interruption of Firm Demand for each instance should the contingencies occur during summer system peak conditions. It should be noted that the two, 115kV lines are radial lines that today are considered part of the BES. However, in the future it is possible that these lines would be excluded from the BES based on exclusion E1 in the proposed NERC BES 100 kV and up definition. c. 20 MW of load for each of the two instances during summer system peak conditions. d. The total cost to re-conductor both transmission lines is estimated at $M. The cost is estimated to be approximately split evenly for each of the two transmission lines. Distribution transformation additions are also planned. e. The present estimate for completion of the reinforcements is. f. In the 2010 assessment, overload was seen in 2010 and the reinforcement project was expected to be completed in 2011. However, the present estimate for completion of the reinforcements is May 20. g. Given the present status of in-service expectation for the line re-conductoring project, there would continue to be interruption of demand if each contingency were to occur during summer peak conditions in years 2012 & 2013.
K	a. 2010, 2011, 2012 Note: Yes. K does plan utilizing footnote b following a single

Organization	Question 3a Comment
	contingency. The footnote is applied in anticipation of the next outage. Transmission system stays within both thermal and voltage limits post category B contingencies. b. The statistic of each unique instance is not tracked. There are a number of areas on the transmission system where this can take place. Load Shedding or generation re-dispatch as stated in footnote B can occur with a number of variations on a group of outages. c. K does not track unique instances of the quantity of load that needs to be shed to mitigate category C3 load shedding associated with footnote B. K believes that there are many combinations of contingencies that will require implementation of footnote B. A few instances require more than 100 MW of load to be impacted but less than 200 MW. d. Not Known e. Not known f. Not known at this time g. The draft 2012 assessment includes load shedding in anticipation of the next outage.
Comment: This data was not considered as the respondent provided data for Category C3 Contingencies.	
L	a. 2010, 2011, and 2012 Assessment Years b. 1. 2010, 2011, and 2012 Assessments The 230 kV Line normally serves Substation. The 230 kV Line is also connected to Substation in a flip-flop scheme, but the connection is normally open. Substation has one 230/115 kV and two 230/70 kV Transformers. An outage of the 230 kV Line will trigger the SPS which opens the 115 kV tie of the 230/115 kV Transformer. This action will result in momentarily dropping roughly 140 MW of load connected to the two 230/70 kV transformers. All customers will be restored within 1 minute when the flip-flop

Organization	Question 3a Comment
	scheme connects the 230 kV Line to Substation. 2. 2010 Assessment The 115 kV Line and the 115 kV Line serve Substation. An outage of the 115 kV Line or the 115 kV Line results in an overload of the remaining line. The resulting overload triggers the SPS which drops 40 MW of 70 KV and 115 kV load connected to Substation. 3. 2010 and 2011 Assessment The 230/60 kV Transformers Nos. 1 and 2/2a serve the 60 kV area. An outage of the 230/60 kV Transformer No. 1 results in an overload of the parallel 230/60 kV Transformer No. 2/2A triggering the Overload Scheme which drops 40 MW load at 60 kV Substation. 4. 2010, 2011, and 2012 Assessments The 115 kV Line and the 115 kV Line, feed the same 115 kV load area. An outage of the 115 kV Line results in an overload of the 115 kV Line. This single contingency event triggers the Overload Scheme which drops roughly 20 MW of load at 115 kV Substation. c. 1. SPS: 140 MW 2. SPS: 40 MW 3. Overload Scheme: 40 MW 4. Overload Scheme: 20 MW d. 1. SPS: One option to eliminate the load dropping scheme, is to convert the 230 kV bus to a ring bus operation. The 5-element new ring bus would cost about $M. 2. SPS: A transmission reinforcement, 70 kV to 115 kV Conversion, designed to eliminate the need for load interruption was completed in at a cost of $M. 3. Overload Scheme: Replacement of the 230/60 kV Transformer No. 2/2A is scheduled to be completed by summer at a cost of about $M. 4. Overload Scheme: In order to eliminate the load dropping scheme, the 115 kV Line would need to be re-conductored at a cost of about $M.

Organization	Question 3a Comment
	e. 1. SPS: None - load is automatically restored within 1 minute. 2. SPS: Transmission reinforcement already completed. The 70 kV to 115 kV Conversion was released to operations on 3. Overload Scheme: Summer 2013 4. Overload Scheme: None f. 1. SPS: 2. SPS: 3. Overload Scheme: 4. Overload Scheme: g. 1. SPS: 2. SPS: SPS no longer required and is not included as mitigation in the assessment 3. Overload Scheme: Overload scheme is no longer required and is not included as mitigation in the assessment 4. Overload Scheme:
Comment: The 1st instance was not considered since the load dropped was automatically restored.	
M	a. 2010. No instances are found in 2011 or 2012 Assessments. b. In a winter peak situation, low voltages show up in the 115 kV area following a loss of 115 kV. Affected buses are as follows: 115 kV, 115 kV, 115 kV, In this case approximately 39 MW of winter peak load at 115 kV will be shed by UVLS in addition to any load at 115 kV. c. See (b). d. The project is a 230 kV line and will eliminate the need for this UVLS for single contingencies. The project cost is approximately $M and is expected to be

Organization	Question 3a Comment
	completed in September of 20. e. See (d). f. The area is mentioned in assessments dating back to 2006. g. 2010
N	a. 2011 No planned interruption of Firm Demand. 2010 Interruption of Firm Demand. 2009 Interruption of Firm Demand. Note: In some instances following a single contingency, the term shed load is used in our Planning Assessments to address BES performance requirements following a single contingency. Typically this is done to address possible violations at the Point of Interconnection serving a neighboring LSE absent any guidance from said LSE to mitigate the possible violation. This means that load shed would be required within the LSE's control area where N has no planning or operation control. The LSE has their own plan of action and has not shared this information with N. b. 1) 2011/none 2) 2010/ ~40MW/ 115kV/ Description: OPEN LINE FROM BUS TO BUS/ PlanningModelYear: 2012S/ LSESheddingLoad: 3) 2010/ ~40MW/ 138kV/ OPEN LINE FROM BUS TO BUS / PlanningModelYear: 2012S/ LSESheddingLoad: 4) 2010/ ~3MW/ 138kV/ Description: OPEN LINE FROM BUS TO BUS / PlanningModelYear: 2012S/ LSESheddingLoad: 5) 2010/ ~20MW/ 138kV/ Description: OPEN LINE FROM BUS TO / PlanningModelYear: 2016S/ LSESheddingLoad: 6) 2010/ ~15MW/ 138kV/ Description: OPEN LINE FROM BUS TO BUS

Organization	Question 3a Comment
	PlanningModelYear: 2016S/ LSESheddingLoad: 7) 2010/ ~63MW/ 138kV/ Description: OPEN LINE FROM BUS TO BUS / PlanningModelYear: 2016S/ LSESheddingLoad: 8) 2010/ ~40MW/ 115kV/ Description: OPEN LINE FROM BUS TO BUS / PlanningModelYear: 2016S/ LSESheddingLoad: 9) 2010/ ~40MW/ 138kV/ Description: OPEN LINE FROM BUS TO BUS / PlanningModelYear: 2016S/ LSESheddingLoad: 10) 2010/ ~3MW/ 138kV/ Description: OPEN LINE FROM BUS TO BUS / PlanningModelYear: 2016S/ LSESheddingLoad: 11) 2010/ ~62MW/ 115kV/ Description: OPEN LINE FROM BUS TO BUS / PlanningModelYear: 2016S/ LSESheddingLoad: 12) 2010/ ~40MW/ 138kV/ Description: OPEN LINE FROM BUS TO BUS OPEN LINE FROM BUS TO BUS CKT 1/ PlanningModelYear: 2016S/ LSESheddingLoad: 13) 2010/ ~61MW/ 138kV/ Description: OPEN LINE FROM BUS TO BUS OPEN LINE FROM BUS TO BUS / PlanningModelYear: 2016S/ LSESheddingLoad: 14) 2010/ ~4MW/ 115kV/ Description: OPEN LINE FROM BUS TO BUS OPEN LINE FROM BUS TO BUS / PlanningModelYear: 2016S/ LSESheddingLoad: 15) 2009/ ~7MW/ 115kV/ Description: OPEN LINE FROM BUS TO BUS / PlanningModelYear: 2009S/ LSESheddingLoad: 16) 2009/ ~7MW/ 115kV/ Description: OPEN LINE FROM BUS TO BUS / PlanningModelYear: 2009S/ LSESheddingLoad: 17) 2009/ ~6MW/ 115kV/ Description: OPEN LINE FROM BUS TO BUS / PlanningModelYear: 2009W/ LSESheddingLoad: 18) 2009/ ~6MW/ 115kV/ Description: OPEN LINE FROM BUS TO BUS / PlanningModelYear: 2009W/ LSESheddingLoad: 19) 2009/ ~4MW/ 69kV/ Description: OPEN LINE FROM BUS TO BUS /

Organization	Question 3a Comment
	PlanningModelYear: 2009W/ LSESheddingLoad: 20) 2009/ ~4MW/ 69kV/ Description: OPEN LINE FROM BUS TO / PlanningModelYear: 2009W/ LSESheddingLoad: 21) 2009/ ~2MW/ 69kV/ Description: OPEN LINE FROM BUS TO BUS / PlanningModelYear: 2009W/ LSESheddingLoad: 22) 2009/ ~2MW/ 69kV/ Description: OPEN LINE FROM BUS TO BUS / PlanningModelYear: 2009W/ LSESheddingLoad: 23) 2009/ ~11MW/ 115kV/ Description: OPEN LINE FROM BUS TO BUS / PlanningModelYear: 2010S/ LSESheddingLoad: 24) 2009/ ~11MW/ 115kV/ Description: OPEN LINE FROM BUS TO BUS / PlanningModelYear: 2010S/ LSESheddingLoad: 25) 2009/ ~6MW/ 115kV/ Description: OPEN LINE FROM BUS TO BUS OPEN LINE FROM BUS TO BUS / PlanningModelYear: 2009S/ LSESheddingLoad: 26) 2009/ ~6MW/ 115kV/ Description: OPEN LINE FROM BUS TO BUS / PlanningModelYear: 2009S/ LSESheddingLoad: 27) 2009/ ~20MW/ 115kV/ Description: OPEN LINE FROM BUS TO BUS / PlanningModelYear: 2009S/ LSESheddingLoad: 28) 2009/ ~6MW/ 115kV/ Description: OPEN LINE FROM BUS TO BUS OPEN LINE FROM BUS TO BUS CKT 1/ PlanningModelYear: 2009W/ LSESheddingLoad: 29) 2009/ ~2MW/ 115kV/ Description: OPEN LINE FROM BUS TO BUS OPEN LINE FROM BUS TO BUS OPEN LINE FROM BUS TO BUS / PlanningModelYear: 2009W/ LSESheddingLoad: c. See data in question 3.b. d. From data in question 3.b. Item 2 & 8: Load shed is within the specified LSE or switching internal within their

Organization	Question 3a Comment
	transmission system. Their specific mitigation plan of action has not been shared with N. Items 3-7, 9, 10, 12, 13: LSE will move their entire load, thus load shedding will not be applicable after this date as noted in the model. Items 11: Load shed is within the specified LSE or switching internal within their transmission system. Their specific mitigation plan of action has not been shared with N. It should also be noted that this LSE has added and continues to added generation which could alleviate, if not eliminate any load shed internal to their system Item 14: $M, In-Service Date (ISD) Items 15-16, 23-24: , $M, ISD, Items 17,18,25,26,28: $M, ISD Items 19-22, 27,29: $M, ISD e. See response to question 3.d. f. 2009 g. 2010. It should be noted that typically within the control area, the planned interruption of Firm Demand has been used in the interim only as a measure of last resort until transmission system reinforcements (upgrades) are budgeted, permitted and built. Once the transmission upgrades are built, the interruption of Firm Demand is not an issue under the consideration of normal load growth.
Comment: Data from the 4 69 kV lines cited above (items 19 – 22) not counted as these are not BES Facilities.	
O	a. 2011 and 2012 Planning Assessments b. 1. UVLS System: Loss of the 230/115-kV transformer (Cat B3); 9 MW,115-kV & 11 MW,69-kV. 2. UVLS System: Loss of the 230/115-kV transformer (Cat B3); 14 MW,115-kV.

Organization	Question 3a Comment
	c. 1. UVLS System: 20 MW. 2. UVLS System: 14 MW. d. 1. UVLS System:$ Million. 2. UVLS System:$ Million. e. 1. UVLS System: 20 2. UVLS System: 20. f. 2011 g. 2012
P	a. 2011, 2010, 2009 b. The are fed by two 138 kV lines. On loss of one of those lines, the voltage stability is close to collapse and the remaining line may overload at peak loads. As a result, an Undervoltage Load Shedding Scheme (UVLS) sheds load to protect the voltage stability, which, consequently, also protects the thermal loading on the lines. Starting in a series capacitor will be installed just south of which will eliminate most of the voltage stability issues and a Special Protection System will be installed to supplement the UVLS scheme to shed load to protect the thermal loading of the two lines north. c. Between 20MW in the near-term horizon to about 55MW in the long-term horizon. d. We have not done an official estimate, but conceptual estimates are in the $ Million plus range; which is not a wise investment considering that the load that is planned to be shed currently is also subject to consequential load loss for loss of the single radial line from. Hence, the investment would have negligible impact on the customer experience.

Organization	Question 3a Comment
	e. No investments are planned, see response to 3.d. f. The first year identified in the most recent Planning Assessment is 2013. g. Please see response to question 3.f.
Q	a. 2012 b. Instance 1: A 161kV line outage in: We plan to drop up to 28 MW of Firm Demand to correct a 110% overload on a 138 kV line, 13MW at the 138kV level and 15MW at the 46kV level c. Just one instance in, so the answer is 28 MW d. The instance can be eliminated with a new 138 kV line, estimated cost is $M. e. The solution is in the planning phase with an in-service date of. f. The 161 kV line outage concern was identified in the spring g. The most recent instance of planned interruption of Firm Demand following a single contingency was identified in 2012.
R	a. (through e.) 2011 Assessment Contingency kV (Cont) MW ISD Cost ($M) 500/115kV Auto 115kV 3.48 Summer 2012 $ Line 138kV 75.20 Summer 2013 $ Line 138kV 3.70 Summer 2013 $ Line 115kV 1.24 Summer 2013 $ Line 138kV 7.71 Summer 2013 $ Line 115kV 15.68 Summer 2014 $ Line 115kV 2.09 Summer 2014 $ Line 230kV 11.33 Summer 2015 $ Line 115kV 5.91 Summer 2015 $ Line 115kV 10.86 Summer 2015 $ Line 115kV 19.81

Organization	Question 3a Comment
	Summer 2015 $ Line 500kV 3.36 Summer 2018 $ Line 500kV 17.52 TBD 2010 Assessment Contingency kV (Cont) MW ISD Cost ($M) Line 115kV 4.99 Summer 2014 $ Line 115kV 0.33 Summer 2013 $ Line 115kV 5.00 Summer 2013 $ 500/115kV Auto 115kV 8.62 Summer 2013 $ Line 115kV 7.14 Summer 2012 $ 230/115kV Auto 115kV 2.69 Summer 2012 $ 230/115kV Auto 115kV 12.50 Winter 2011 $ Line 500kV 28.31 Summer 2013 $ f. 2010 - Loss of 230/115 kV auto g. 2011 - Loss of 230 kV line 2010 - Loss 115 kV line 2011 - Loss of 500 kV line
S	a. The Substation load loss is an existing situation that is planned to be mitigated in. The need for planned or controlled interruption of supply has also been identified for two future. This need for load interruption arises starting in for the 90 MW and for the 128 MW. b. Planning Assessments identified the possibility of non-consequential load loss at 120 kV Substation for an N-1 contingency of the single 230 kV transmission source. This load is a single industrial customer in a remote location that cannot be supplied by the underlying 55 kV system after a 230 kV outage. The described N-1 contingency load loss is planned to be mitigated in by projects associated

Organization	Question 3a Comment
	with the addition of two new renewable generators in the area. Expansion Planning Assessments include specific planned or controlled interruption of supply for single contingencies within the Bulk Electric System for two new remote additions. The loads are extremely large single loads (90 and 128 MW) located long distances from strong electrical infrastructure. Unlike many high demand electrical loads, these loads cannot be moved closer to the EHV BES. The locations of these loads are linked directly to the. These loads belong to industrial customers with sophisticated knowledge of electrical service who have requested these planned or controlled interruption of supply service plans. A major concern to these customers is the length of time that would be required to permit and construct any alternate plan of service that would eliminate the planned interruption of their loads for an N-1 contingency. These three load dropping plans of service each only interrupt the specific single industrial customer mentioned. No other customers require load tripping for these service plans. 1. 8 MW, 120 kV for an N-1 contingency of the 230 kV 2. 90 MW, 120 kV for loss of one of the two 120 kV sources to the location. Service to is radial from the tap to the. Loss of the radial line also results in a loss of this customer load. 3. 128 MW, 120 kV for loss of the two 120 kV sources to the location. Service to the is radial from the tap to the. Loss of the radial line also results in a loss of this customer load. c. 1. Substation 8 MW 2. 128 MW 3. 90 MW d. $ million for

Organization	Question 3a Comment
	2. $ million and a 3-5 year delay for 3. $ million and a 3-5 year delay for For each of the large load additions, the customer was provided options which would not have required planned load interruption for a single contingency. These customers specifically rejected those options, primarily because of delayed timing required to permit new transmission lines and the resulting project delay. The lost productivity from three to five year delays was unacceptable for these major operations. These three customers are the only loads subject to this type of non-radial, N-1 curtailment. e. As described above there are plans to mitigate the Substation load loss for N-1 contingencies by. Unless requested by or, or driven by additional load growth in the region, there are no plans to eliminate these two cases of planned interruption of Firm Demand. f. 1990 only g. 2012
Comment: Only the 1st instance shown in the table is Firm Demand for an N-1 Contingency. The other two instances are interruptible load and were not considered.	
T	a. 2012 b. 115 kV Under Voltage Load Shedding and 115 kV Under Voltage Load Shedding for the 115 kV contingency during winter peak conditions. (MW details found below in part (c)) 115 kV Under Voltage Load Shedding and 115 kV Under Voltage Load Shedding for 115 kV contingency during winter peak conditions. (MW details found below in part (c)) c. 2012 Assessment (models with interruption of firm demand for TPL-002)

Organization	Question 3a Comment
	2012 Winter Peak 2017 Winter Peak 115 kV 0 MW 0 MW 115 kV 3.6 MW 4.1 MW 115 kV 5.5 MW 6.4 MW 115 kV 2.3 MW 2.7 MW d. 115 kV & 115 kV: $ Million 115 kV & 115 kV: $ Million e. 115 kV & 115 kV: 115 kV & 115 kV: f. 2009 g. 2012 – The primary cause of under voltage at the substations is loss of the 115 kV line at times of low generation output from the. For this condition, the remaining 115 kV source from is not strong enough to support the area loads. At this time, under voltage load shedding is used to mitigate this concern. The situation outlined above does not affect bulk transmission facilities, but is a local load-serving problem caused by limited transmission facilities serving the area. Based on our knowledge, the Under Voltage Load Shedding at has never operated due to a category B contingency since it was installed.

I - response to 3b.

2010 Summer Assessment Examples

From	NAME	BASKV	AREA	To	NAME	Overload	Name of Contingency 1 (N-1)	Mitigation Plan	Permanent Solution to the problem
		115				109.84%		Curtail 10 MW.	
		115				125.65%		Curtail 12 MW of load	
		115				109.16%		Curtail 5 Mw	
		115				129.50%		Curtail 10 Mw.	

2011 Assessment Examples

Example 1:
The 115 kV line from was planned to be under construction during the summer of 2012. During this season, several 115 kV outages caused low voltages which require load curtailments as shown below.

115 kV line

Contingency	**Bus**	**VCont**	**Vmax**	**Vmin**	**Response Plan**
115 kV line		0.75	1.05	0.90	Shed load (8.9 MW), (22.9 MW and 18.2 MW)
		0.74	1.05	0.90	
		0.82	1.05	0.90	
		0.80	1.05	0.90	
115 kV line		0.46	1.05	0.90	Shed load (8.9 MW), (22.9 MW)
		0.45	1.05	0.90	
		0.53	1.05	0.90	
138 kV line		1.05	1.05	0.90	Reduce cap bank to no steps 0 MVAR
		1.06	1.05	0.90	
138/115 kV transformer		1.05	1.05	0.90	
		1.06	1.05	0.90	

Example 2:

The 115 kV line from was planned to be under construction during the summer of 2012. During this season, several 115 kV outages caused low voltages which require load curtailments as shown below.

115 kV line

Contingency	Bus	VCont	Vmax	Vmin	Response Plan
115 kV line		0.84	1.05	0.90	Shed load (22.9 MW)
		0.84	1.05	0.90	
		0.84	1.05	0.90	
		0.87	1.05	0.90	
		0.86	1.05	0.90	
115 kV line		0.49	1.05	0.90	Shed load (22.9 MW)
		0.48	1.05	0.90	
		0.48	1.05	0.90	
		0.55	1.05	0.90	

Example 3:
The 115 kV line from was planned to be under construction during the summer of 2012. During this season, several 115 kV outages caused low voltages which require load curtailments as shown below.

115 kV line

Contingency	Bus	VCont	Vmax	Vmin	Response Plan
115 kV line		0.83	1.05	0.90	Shed load (22.9 MW)
		0.83	1.05	0.90	
		0.83	1.05	0.90	
		0.83	1.05	0.90	
		0.86	1.05	0.90	
		0.86	1.05	0.90	
115 kV line		0.48	1.05	0.90	Shed load (22.9 MW)
		0.47	1.05	0.90	
		0.47	1.05	0.90	
		0.47	1.05	0.90	
		0.54	1.05	0.90	

Example 4:
The 115 kV line from was planned to be under construction during the fall of 2012. During this season, several thermal overloads were noticed and planned mitigations are shown below.

115 kV line

Contingency	Monitored Branch	Rating (MVA) Flow (MVA) % MVA Response Plan	Contingency	Monitored Branch	Rating (MVA) Flow (MVA) % MVA Response Plan
345/115 kV transformer	115 kV line	198	233.9	118.1	Curtail 120 MW to 233 MW.
115 kV line	transformer	336	352.8	105.0	Shed load at (2.7 MW), (2.8 MW), (2.4 MW), (4.6 MW), and (4.6 MW);

END OF REPORT

Exhibit G

Summary of Proposed TPL Standards Development Authorization, Posting, and Balloting History

EXHIBIT G

Summary of Post-Remand Development Authorization, Posting, and Balloting History

A. Post-Remand Authorization

In response to Order No. 762 and the TPL NOPR, the Standards Committee directed the Drafting Team to respond quickly to directives in those orders as well as the directives in Order No. 693 to address planned non-consequential load shed under limited circumstances for single Contingencies.

B. The First Posting (July 2012): Informal Comment Period

The revised Footnote was posted for a first, informal comment period from July 31, 2012 through August 29, 2012.[1] NERC received 51 sets of comments from more than 117 different individuals, including 81 companies and representing 9 of the 10 industry segments. Commenters provided feedback on the draft Footnote. In response to the comments received, the Drafting Team revised and clarified both the Footnote and Attachment 1. The Drafting Team then requested that the Footnote and Proposed TPL Standards be moved forward to the initial ballot and comment phase of the process.

C. The Second Posting (October 2012): Formal Comment Period and Initial Ballot

A revised draft of the Footnote was posted for a 45-day public comment period (from October 5 through November 19, 2012) and subject to an initial ballot (from November 9 through November 19, 2012).[2] The second draft reflected the revisions and clarifications identified in Section B immediately above. NERC received 61 sets of

[1] *See Id*. at pp. 789. **Exhibit I** page citations refer to page numbers of the pdf file filed with the Petition and this **Exhibit H**.

[2] *See Id.* pp. 1087.

comments from more than 149 different individuals, including 112 companies and representing 9 of the 10 industry segments. Commenters provided feedback on the Footnote and Attachment 1. The ballot was not approved, with 56.18% voting to approve .[3] In response to the comments received, the Drafting Team further revised and clarified both the Footnote and Attachment 1.

D. The Third Posting (December 2012): Formal Comment Period and Successive Ballot

A third draft of the Footnote was posted for a 30-day public comment period (from December 10, 2012 through January 11, 2013), and subject to a successive ballot (from January 2 through January 11, 2013).[4] The third draft reflected further revisions and clarifications as noted in Section C. NERC received 49 sets of comments from more than 132 different individuals, including 48 companies and representing 9 of the 10 industry segments. The ballot was not approved, with 65.77% voting to approve, just short of the two-thirds required to approve the ballot.

The Drafting Team made one change to the Footnote to address industry comments following the third posting. Specifically, the main body of the Footnote and Appendix 1 were revised to address a specific jurisdictional differences for non-US entities – namely, that the 75 MW limit on planned, non-consequential load loss included in the Footnote and Attachment 1 would not apply to Canadian or Mexican registered entities. In addition, non-material clarifying, grammatical and typographical changes were implemented. Because the revisions did not change the technical content or intent

[3] *See Id.* pp. 1095.
[4] *See Id.* at pp. 1333.

of the Proposed TPL Standards, and in order to support meeting the approaching February 2013 deadline, the Standards Committee determined to move the project forward to a recirculation ballot.

E. **Final Balloting (January 2013): Recirculation Ballot**

The Footnote proceeded to a recirculation ballot that concluded on January 31, 2013.[5] The recirculation ballot was approved, with 69.63% of the weighted segment vote voting to approve the Footnote.

F. **Board of Trustees Approval**

The final draft of the stakeholder-approved Footnote, including Appendix 1, to be included in the Proposed TPL Standards, was presented to NERC's Board of Trustees for approval on February 7, 2013. The Board of Trustees approved the Footnote incorporated into the Proposed TPL Standards, and directed NERC staff to file the Proposed TPL Standards with applicable regulatory authorities.

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[5] *See Id.* at pp. 1480.

Exhibit H

Consideration of Comments

Project 2010-11
TPL Table 1 Order

Related Files

Status:
Adopted by the NERC Board of Trustees on February 7, 2013 and pending regulatory approval.

Purpose / Industry Need:
The SAR is to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote ‘b’, regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010. The SAR provides a revision to TPL Table 1 footnote ‘b’ to provide clarity to industry with regard to the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. The referenced table appears in TPL-001, TPL-002, TPL-003, and TPL-004 so while the FERC Order was for TPL-002, the change is reflected in all 4 standards.

Draft	Action	Dates	Results	Consideration of Comments
TPL-001-3 (formerly TPL-001-2a) Clean | Redline to Last Posting Implementation Plan Clean | Redline to Last Posting **TPL-002-2b (formerly TPL-002-1c)** Clean | Redline to Last Posting Implementation Plan Clean | Redline to Last Posting	Recirculation Ballot Info>> Vote>>	01/22/13 - 01/31/13 (closed)	Summary>> Ballot Results>>	
Draft 8 **TPL-001-2a** Clean | Redline to Last Posting Implementation Plan **Draft 7** **TPL-002-1c**	Successive Ballot Updated Info>> Info>>	01/02/13 - 01/11/13 (closed)	Summary>> Ballot Results>>	

Clean | Redline to Last Posting Implementation Plan **Supporting Materials:** Unofficial Comment Form (Word)	Vote>>			
	Formal Comment Period Info>> Submit Comments>>	12/10/12 - 01/11/13 (closed)	Comments Received>>	Consideration of Comments **(8)**
Draft 7 **TPL-001-2a** Clean | Redline to Last Posting Implementation Plan **Draft 6** **TPL-002-1c** Clean | Redline to Last Posting Implementation Plan **Supporting Materials:** Unofficial Comment Form (Word) Data Request Summary FERC Order 762	Initial Ballot Updated Info>> Info>> Vote>>	11/09/12 - 11/19/12 (closed)	Updated Summary>> Full Record>>	
	Formal Comment Period Info>> Submit Comments>>	10/05/12 - 11/19/12 (closed)	Comments Received>>	Consideration of Comments **(7)**
	Join Ballot Pool>>	10/05/12 - 11/05/12 (closed)		
Draft 1 **TPL-001-3** Clean | Redline to Last Approved **TPL-002-1** Clean | Redline to Last Approved	Comment Period Info>> Submit Comments>>	07/31/12 - 08/29/12 (closed)	Comments Received>>	Consideration of Comments **(6)**

Supporting Materials: Unofficial Comment Form (Word) SAR FERC Order 762				
On April 19, 2012 FERC issued Order 762 remanding TPL-002-1b and FERC proposed to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.				
Implementation Plan **TPL-001-1** Clean | Redline to last posting Redline to last approval **TPL-002-1b** Clean | Redline to last posting Redline to last approval **TPL-003-1a** Clean | Redline to last posting Redline to last approval **TPL-004-1** Clean | Redline to last posting Redline to last approval	Recirculation Ballot Info>> Vote>>	01/26/11 – 02/05/11 (closed)	Summary>> Full Record>>	
	Initial Ballot	12/27/10 -	Summary>>	Consideration of Comments

Implementation Plan **TPL-001-1** Clean | Redline to last posting Redline to last approval **TPL-002-1b** Clean | Redline to last posting Redline to last approval **TPL-003-1a** Clean | Redline to last posting Redline to last approval **TPL-004-1** Clean | Redline to last posting Redline to last approval **Supporting Materials:** Comment Form (Word)	Info>> Vote>>	01/05/11 (closed)	Full Record>>	**(5)**
	Ballot Pool Info>>	11/19/10 - 12/22/10 (closed)		
	Comment Period Info>> Submit Comments>>	11/19/10 - 01/05/11 (closed)	Comments Received>>	Consideration of Comments **(4)**
Implementation Plan TPL-001-1 Clean | Redline to last posting TPL-002-1b Clean | Redline to last posting TPL-003-1a	Comment Period Submit Comments>> | Info>>	09/08/10 - 10/08/10 (closed)	Comments Received>>	Comment Report **(3)**

Clean | Redline to last posting TPL-004-1 Clean | Redline to last posting **Supporting Materials:** Comment Form (Word)				
SAR Implementation Plan TPL-001-1 Clean | Redline to last approval TPL-002-1b Clean | Redline to last approval TPL-003-1a Clean | Redline to last approval TPL-004-1 Clean | Redline to last approval **Supporting Materials:** Comment Form (Word)	Initial Ballot Vote>> | Info>>	05/17/10 - 05/27/10 (closed)	Summary>> Full Record>>	Comment Report **(2)**
	Pre-ballot Review Join>> | Info>>	04/15/10 - 05/17/10 (closed)		
	Comment Period Submit Comments>> | Info>>	04/15/10 - 05/26/10 (closed)	Comments Received>>	Comment Report **(1)**

Consideration of Comments on Project 2010-11: TPL Table 1 Order and Comments Submitted with Initial Ballots

The Standards Committee thanks all commenters who submitted comments on the proposed SAR for the TPL Table 1 Order. The SAR proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which requires the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards.

The SAR, implementation plan, and the clean and redline versions to the four TPL standards were posted for a 40-day public comment period from April 15, 2010 through May 27, 2010. Stakeholders were asked to provide feedback on the standards through a special electronic comment form. There were 22 sets of comments, including comments from more than 80 different people from approximately 40 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

The initial ballot for the proposed changes to the four TPL standards was conducted from May 17-27, 2010. The comments submitted with initial ballots and the drafting team's responses to those comments are also contained in this report.

All comments submitted during the comment period and the initial ballot results are posted on the following page:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Based on stakeholder comments, the drafting team has made some additional changes to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

The following bullet was added to Footnote 'b' to provide the flexibility requested by stakeholders with respect to interrupting Demand, but with appropriate constraints to protect reliability. The >90% demand level was selected to ensure that the number of hours with exposure to demand loss was not unlimited. A 90% demand level is a reasonably stressed case for most systems and the number of hours when peak demands are >90% is a small percentage of the time for most systems. A large percentage of the transmission lines that directly serve distribution customers are 161 kV or lower voltages. Ten percent (10%) of the loading on a high capacity 161 kV transmission line is approximately 50 MW.

- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW

The following bullet was added to Footnote 'b' to clarify that it is acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

The above changes will be noted to stakeholders before the initiation of the recirculation ballot.

The revised Footnote 'b' is:

b) No interruption of projected customer Demand is allowed except:

  - Interruption of Demand that is directly served by the elements that are removed from service as a result of the Contingency
  - Planned or controlled interruption of Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities
  - Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
  - Interruptible Demand or Demand-Side Management

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

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

Comments and Responses from Formal Comment Period:

Comments and Responses from Initial Ballot:

The Industry Segments are:

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

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
4.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
5.	Sylvain Clermont	Hydro-Quebec TransEnergie		1
6.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
7.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
8.	Ben Eng	New York Power Authority	NPCC	4
9.	Brian Evans-Mongeon	Utility Services	NPCC	8
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
15.	Randy MacDonald		New Brunswick System Operator	NPCC					2				
16.	Bruce Metruck		New York Power Authority	NPCC					6				
17.	Lee Pedowicz		Northeast Power Coordinating Council	NPCC					10				
18.	Robert Pellegrini		The United Illuminating Company	NPCC					1				
19.	Saurabh Saksena		National Grid	NPCC					1				
20.	Michael Schiavone		National Grid	NPCC					1				
2.	Group	Philip R. Kleckley	South Carolina Electric & Gas	X		X		X					
	Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
1.	Bob Jones		Southern Company Services - Trans.	SERC					1				
2.	David Marler		Tennessee Valley Authority	SERC					1				
3.	Charles Long		Entergy	SERC					1				
4.	James Manning		North Carolina Electric Membership Corporation	SERC					3				
5.	Pat Huntley		SERC Reliability Corporation	SERC					10				
3.	Group	John Bee	Exelon Transmission Strategy & Compliance	X		X		X					
	Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
1.	Mortenson, Eric		:(ComEd)	RFC					1				
2.	Weaver, David W		(PECO)	RFC					1				
3.	McHugh, Kathleen P		(PECO)	RFC					1				
4.	Kay, Thomas W		(ComEd)	RFC					1				
5.	Szymczak, Ronald		(ComEd)	RFC					1				
6.	Chu, Ron F		(PECO)	RFC					1				
7.	Donnelly, Michael J		(PECO)	RFC					1				
8.	Kliros, Chris B		(ComEd)	RFC					1				
9.	Mills, Paul M		(ComEd)	RFC					1				
10.	Webb, Becky		(ComEd)	RFC					1				
4.	Group	Denise Koehn	BPA, Transmission Reliability Program	X		X		X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Chuck Matthews		BPA, Transmission Planning	WECC					1				
2.	Berhanu Tesema		BPA, Transmission Planning	WECC					1				
3.	Larry Furumasu		BPA, Transmission Planning	WECC					1				
4.	Kyle Kohne		BPA, Transmission Planning	WECC					1				
5.	Don Watkins		BPA, Transmission System Operations	WECC					1				
6.	Rebecca Berdahl		BPA, Power, Long Term Sales and Purchases	WECC					3				
5.	Group	Carol Gerou	Midwest Reliability Organization										X
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Chuck Lawrence		American Transmission Company	MRO					1				
2.	Tom Webb		Wisconsin Public Service	MRO					3, 4, 5, 6				
3.	Terry Bilke		Midwest ISO Inc.	MRO					2				
4.	Jodi Jenson		Western Area Power Administration	MRO					1, 6				
5.	Ken Goldsmith		Alliant Energy	MRO					4				
6.	Dave Rudolph		Basin Electric Power Cooperative	MRO					1, 3, 5, 6				
7.	Eric Ruskamp		Lincoln Electric System	MRO					1, 3, 5, 6				
8.	Joseph Knight		Great River Energy	MRO					1, 3, 5, 6				
9.	Joe DePoorter		Madison Gas & Electric	MRO					3, 4, 5, 6				
10.	Scott Nickels		Rochester Public Utilities	MRO					4				
11.	Terry Harbour		MidAmerican Energy Company	MRO					1, 3, 5, 6				
6.	Group	Richard Kafka	Pepco Holdings, Inc.	X		X		X	X				
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Jim Summers		Delmarva Power and Light Co.	RFC					1				
2.	John Radman		Potomac Electric Power Company	RFC					1				
7.	Group	Ben Li	IESO		X								
	Additional Member		Additional Organization	Region					Segment Selection				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.		Bill Phillips	MISO	MRO									
2.		James Castle	NYISO	NPCC									
3.		Charles Yeung	SPP	SPP									
4.		Lourdes Estrada-Salinero	CAISO	WECC									
5.		Patrick Brown	PJM	RFC									
6.		Steve Myers	ERCOT	ERCOT									
8.	Group	Frank Gaffney	Florida Municipal Power Agency	X			X	X	X				
		Additional Member	**Additional Organization**	**Region**					**Segment Selection**				
1.		Timothy Beyrle	Utilities Commission of New Smyrna Beach	FRCC					4				
2.		Greg Woessner	Kissimmee Utility Authority	FRCC					1				
3.		Jim Howard	Lakeland Electric	FRCC					1				
4.		Lynne Mila	City of Clewiston	FRCC					3				
5.		Joe Stonecipher	Beaches Energy Services	FRCC					1				
6.		Cairo Vanegas	Fort Pierce Utility Authority	FRCC					4				
9.	Individual	Stephen Mizelle	Southern Company Transmission	X									
10.	Individual	Robert Casey	Georgia Transmission Corporation (Bulk System Planning)	X									
11.	Individual	Thad Ness	American Electric Power	X		X		X	X				
12.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
13.	Individual	Martin Bauer	US Bureau of Reclamation					X					
14.	Individual	Kirit Shah	Ameren	X		X		X	X				
15.	Individual	Robert W. Roddy	Dairyland Power Cooperative	X		X		X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
16.	Individual	Marty Berland	Progress Energy	X		X		X	X				
17.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
18.	Individual	Charles Lawrence	American Transmission Company	X									
19.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
20.	Individual	Bill Middaugh	Tri-State Generation and Transmission Association, Inc.	X		X		X	X				
21.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
22.	Individual	Dan Rochester	Independent Electricity System Operator		X								

1. **The SDT is proposing a revision to footnote ‘b’ in the TPL tables to comply with FERC Order RM-06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote ‘b’, regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.**

Summary Consideration: The SDT has listened to the comments from the industry, understands the concerns raised, and has made changes to the footnote to balance the various industry concerns while assuring BES reliability.

The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. This is limited by two conditions: >90% demand level and 50 MW. The >90% demand level was selected to ensure that the number of hours with exposure to demand loss was not unlimited. A 90% demand level is a reasonably stressed case for most systems and the number of hours when peak demands are >90% is a small percentage of the time for most systems. A large percentage of the transmission lines that directly serve distribution customers are 161 kV or lower voltages. Ten percent (10%) of the demand on a high capacity 161 kV transmission line is approximately 50 MW.

A 4th bullet has also been added to clarify that it is acceptable to use Interruptible demand and Demand-Side Management.

To match the terminology in the revised footnote with the terminology in the associated column heading (Loss of Demand or Curtailed Firm Transfers) the term, ’Load’ was replaced with ‘Demand’ and the term ‘Firm Transmission Service’ was replaced with ‘firm transfers.’

Footnote ‘b’ now reads:

b)~~-~~No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Duke Energy	No	Duke Energy voted "Negative" on the initial and current ballots of TPL-001-1, primarily because Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We also sought rehearing on the Commission's March 18 Order Setting Deadline for Compliance (Docket No. RM06-16), with respect to this and other issues. We believe that FERC's directive in that Order to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the potential impacts (environmental, historical, archaeological, aesthetic...) of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. Duke offers the following ideas on alternatives for the SDT to consider that will allow for appropriate discretion and facilitate proper planning while allowing non-consequential load loss (NCLL).The standard should allow for dropping of limited amounts of non-consequential load in situations where it would be reasonable for a bounded time period and under restricted system conditions (e.g. 1-3 years only when load is >90 % of peak conditions). Dropping of non-consequential load would be prudent planning in situations where the near term impact of load projections or implementation of nearby transmission/generation projects will alleviate the necessity of an upgrade to meet N-1 conditions. Also, reliability of service to end-use customer is impacted by the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customers' level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to avoid projects without greatly impacting a customer's outage frequency

Organization	Yes or No	Question 1 Comment
		and duration should be acceptable. Use of reliability metrics (e.g. SAIFI/SAIDI/ASAI) should also be considered by the SDT for determination of acceptable use of NCLL.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT discussed the use of reliability metrics for providing flexibility to planners but has not included their use as this would make the implementation too complex.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Midwest Reliability Organization	No	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
Dairyland Power Cooperative	No	DPC concurs with the MRO comments: For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
American Transmission Company	No	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant

Organization	Yes or No	Question 1 Comment
		transmission system modifications.

Response: The SDT has added the fourth bullet to address your concern.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Georgia Transmission Corporation (Bulk System Planning)	No	Georgia Transmission Corporation (GTC) believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We believe that FERC's directive in (Docket No. RM06-16) to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view

Organization	Yes or No	Question 1 Comment
		to allow loss of non-consequential load.We also note that on April 19 NERC filed a request for rehearing with FERC asking that the Commission revise the directive in Paragraph 8 of the March 18 TPL-002 Order to allow NERC the necessary time to incorporate changes to the TPL-002 Reliability Standard through the Reliability Standards Development Process that are necessary to achieve bulk power system reliability. NERC also requested that the Commission grant NERC's Motion for Stay to stay the Order so that a public technical conference with opportunity for comment can be held in order to provide parties an opportunity to meet and discuss the technical considerations of developing a modification to the TPL-002 standard that prohibits the loss of non-consequential firm load in the event of an N-1 contingency. NERC's April 19 filing pointed out that if the Commission's directive to disallow the loss of non-consequential firm load for an N-1 contingency is implemented, a question is presented regarding whether the Reliability Standard still serves the purpose of ensuring the Reliable Operation of the bulk power system by preventing instability, uncontrolled separation, and cascading failures. That is, the Commission's directive sets forth an expectation that NERC is to implement standards that address all loss of load at costs that may not be commensurate with bulk power system reliability, as statutorily defined, which is fundamentally different from what the Reliability Standards were intended to do.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Progress Energy	No	Progress Energy applauds NERC's efforts to improve the footnote (b) language with respect to conditional allowance of curtailing Firm Transmission Service, which is addressed in the second paragraph of the proposed new footnote (b). PE remains concerned, however, that the first paragraph of the proposed new

Organization	Yes or No	Question 1 Comment
		footnote (b) does not allow for curtailment of non-radial non-consequential load. The ability to curtail non-consequential load in the planning horizon can be a useful tool to mitigate local area issues, and has not been detrimental to the Bulk Electric System (BES). Disallowing the curtailment of non-radial non-consequential load essentially prohibits taking action in situations in which the load in question is clearly at a localized self-contained level of the system, i.e. the distribution system(s) served by the Transmission Owner/Operator. Prohibiting the curtailment of local load thus constitutes regulating distribution feeder reliability rather than BES reliability. Events that could be mitigated through the curtailment of local, non-radial non-consequential load are infrequent, and such curtailment has no material effect on the reliability of the BES. PE therefore suggests that the following addition (item (3)) to the first paragraph of the proposed footnote (b) be considered:"No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, and/or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities, and/or (3) Planned or controlled interruption of any additional Load required to mitigate the post-contingency results, provided that the non-consequential load being shed for the event is localized, and provided that the total load shed for the event does not exceed 2% of the Planned system peak demand or 200 MW, whichever value is less."

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT did adopt a limit but felt that 2% of system peak or 200 MW was not equitable for all entities.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Hydro-Québec TransEnergie (HQT)	No	The proposed changes do not adequately address FERC's concerns in RM06-16-009. The Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." The proposed changes to footnote 'b' indicate "No interruption of firm Load is allowed except:... (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities." The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as "the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency." In referencing Order 693, the Commission reiterated its position that TPL standards "should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." "Must" should be used instead of "should" in the last sentence of the footnote, making it to read "Facility Ratings in those regions must also be respected."
Northeast Power Coordinating Council	No	The proposed changes do not adequately address FERC's concerns in RM06-16-009. The Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." The proposed changes to footnote 'b' indicate "No interruption of firm Load is allowed except:... (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities." The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as "the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency." In referencing Order 693, the Commission reiterated its position that TPL standards "should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." "Must" should be used instead of "should" in the last sentence of the footnote, making it to read "Facility Ratings in those regions must also be respected."

Response: The SDT believes that it has been responsive to the FERC directive in that the standards development process has been employed. In the

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3">development of the footnote, the SDT has balanced the need for discretion while addressing local area concerns with the need to assure the reliability of the BES.

‘Must’ is not appropriate in a footnote as it would impose a requirement in the footnote. The SDT has replaced ‘should’ with ‘would’ to correct the grammar.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:
o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.</td></tr>
<tr><td>Tri-State Generation and Transmission Association, Inc.</td><td>No</td><td>Tri-State does believe that the new footnote is an improvement, but thinks there are still some changes necessary. We believe that the word “only” should be removed from the phrase “...where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities” because that discrimination was not required in FERC Order RM-06-16-009. There may be times when facilities near the temporary radial facilities might also fall outside the limits set in reliability criteria but the situation is mitigated if the load shedding occurs at the radial facility.

The meaning of the second paragraph of the new footnote is unclear. Tri-State recommends changing it to "Curtailment of Firm Transmission Service is not allowed unless it is coupled with curtailment-offsetting resources that are obligated to re-dispatch. Further, the curtailment activities cannot result in the shedding of any Firm load or in violations of Facility Ratings, either internal or external to the planning region."</td></tr>
<tr><td colspan="3">Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. Instead of removing the word ‘only’, the 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Southern Company Transmission	No	We propose that the section in double parentheses be deleted. The proposed wording by the drafting team seems to imply that the curtailment of firm transmission service is permitted to address single contingency constraints if coupled with the redispatch of network resources. The original language stated only that curtailments were permitted to prepare for the next contingency, not to address loading related to the initial contingency. The proposed wording could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint. Southern Companies recommend that the original language relating to "preparing for the next contingency" be incorporated into the drafting team's proposal.((Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.)) No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch. where it can It must be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

Organization	Yes or No	Question 1 Comment
Response: The SDT believes that System re-dispatch is an acceptable System adjustment to "remain within applicable Facility Ratings" to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can be only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the Firm Transmission Service cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch do~~es~~ not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
South Carolina Electric & Gas	Yes	For better clarity delete the phrase "when coupled with" in the second paragraph of footnote 'b.'
Response: The SDT did not delete the suggested phrase as it believes it is correct as stated but added commas to make the phrase read more clearly. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~		

Organization	Yes or No	Question 1 Comment
o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Independent Electricity System Operator	Yes	IESO supports the revisions made to footnote 'b' based on the present definitions of BES and Firm Demand and on the understanding that the NERC standards apply only to the BES as defined in the NERC Glossary as follows:"As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." To be clear, our interpretation of the present definition of BES is that it defers to each Regional Reliability Organization to define the elements of the power system that are considered BES and, therefore in the NPCC Region, "BES as defined by NERC" = "BPS as defined by NPCC".
Response: The SDT agrees that the standard applies to the BES as defined in the Glossary.		
BPA, Transmission Reliability Program	Yes	On the firm transfer issues, the term "Firm Transmission Service" should be replaced with "Firm Transfers" to be consistent with the fourth column of the existing Table 1 Transmission System Standards - Normal and Emergency Conditions.
Response: The SDT agrees and has made the change. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW		

Organization	Yes or No	Question 1 Comment
o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
American Electric Power	Yes	
Exelon Transmission Strategy & Compliance	Yes	
Florida Municipal Power Agency	Yes	
IESO	Yes	
Northeast Utilities	Yes	
Pepco Holdings, Inc.	Yes	
US Bureau of Reclamation	Yes	
Manitoba Hydro	Yes	MH agrees with the SDT proposal.
Ameren	Yes	We were ok with the previous language. Though we do not intend to drop non-consequential load for a single contingency, we undersatnd that other ares may have been following such practice without degarding the relaibility of BES. We believe that they can continue this practice if they develop non-firm contracts with these customers.
Response: Thank you for your support.		

2. Are you aware of any conflicts caused by compliance with the proposed language in Table 1 — footnote b and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement? If yes, please identify the conflict.

Summary Consideration: The SDT understands that there may be conflicts as pointed out by respondents; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.

b)~~–~~No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
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~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 2 Comment
Ameren	No	
American Electric Power	No	
American Transmission Company	No	
BPA, Transmission Reliability	No	

Organization	Yes or No	Question 2 Comment
Program		
Dairyland Power Cooperative	No	
Exelon Transmission Strategy & Compliance	No	
Independent Electricity System Operator	No	
Manitoba Hydro	No	
Midwest Reliability Organization	No	
Southern Company Transmission	No	
US Bureau of Reclamation	No	
South Carolina Electric & Gas	No	The comments expressed herein represent a consensus of the views of the above named members of the SERC Engineering Committee Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.
Response: Thank you for your response.		
Hydro-Québec TransEnergie (HQT)	Yes	Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.
Northeast Power Coordinating Council	Yes	Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td>IESO</td><td>Yes</td><td>It should be noted that conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. In RM-06-16-009, the Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." In the US, State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.Similar conflicts may also exist in Canada.</td></tr>
<tr><td>Progress Energy</td><td>Yes</td><td>There is the potential for conflict between Table 1 - Footnote (b) as currently proposed, which can be considered to regulate local distribution reliability without improving BES reliability, and local service reliability issues which are under the purview of state regulatory agencies. For example, the North Carolina Utilities Commission (NCUC) commented regarding this concern in the ballot which ended March 1 in Project 2006-02. Specifically, NCUC commented that they were "...concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1 is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions..." Progress Energy believes that NCUC's concerns are legitimate. BES reliability should address the avoidance and mitigation of cascading outages and BES facility damage, rather than limited, controlled local area loss of load, in order to avoid this conflict and overlap of regulation.</td></tr>
<tr><td colspan="3">Response: The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.</td></tr>
<tr><td>Northeast Utilities</td><td>Yes</td><td>Northeast Utilities (NU) believes the language of the proposed revision to footnote 'b' can be better defined as the proposed revision is subject to interpretation by the different entities and regulatory agencies. Future conflicts can be minimized by further clarifying the proposed revision.

Also, NU is concerned that this new modification does not specify the amount of permissible load shed nor does it require the planning entity to minimize load shedding under this exception.</td></tr>
<tr><td colspan="3">Response: The SDT has made several clarifying changes to the footnote which should alleviate your concerns.

The SDT has modified the footnote for clarity and added constraints in new bullet 3 to address your specific concern.</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Duke Energy	Yes	See response to question #1.
Georgia Transmission Corporation (Bulk System Planning)	Yes	See response to Question #1.
Response: See response to question #1.		
Florida Municipal Power Agency	Yes	This is an area of fuzziness between State jurisdiction and Federal jurisdiction. In all honesty, shedding load for local area impacts has nothing to do with BES reliability and should not be under FERC jurisdiction under Section 215 of the Federal Power Act, but rather State jurisdiction for quality of service issues. However, there is also the matter of FERC jurisdiction over commercial matters and the opportunity to "game" the original footnote by transmission providers by allowing firm load shedding to grant firm transmission service for themselves, thereby avoiding or deferring transmission investment, while at the same time denying or requiring others to build the same transmission avoided in order to obtain transmission service. We can see how difficult it is from a drafting team's perspective in achieving a balanced position between these different matters. The drafting team should be applauded for finding a reasonable position.
Pepco Holdings, Inc.	Yes	This is not an issue for historic PJM members, but as PJM has expanded and as a result of the merger of historic councils into RFC, I am aware that not all regions had standards equal to those of MAAC, and this

Organization	Yes or No	Question 2 Comment
		has been an issue worked out between transmission planners (historic transmission owners) and their local regulators. It is ultimately a cost issue for loss of local load that does not affect the overall reliability of the interconnected BES.
Response: Thank you for your support.		
Tri-State Generation and Transmission Association, Inc.	Yes	We believe that FERC's directive in FERC Order RM-06-16-009 to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load.
Response: The SDT is not in a position to comment on FERC's authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.		

3. Consideration of Comments on Initial Ballot — TPL Table 1 Order (Project 2010-11) May 17–27, 2010

Summary Consideration: The SDT has listened to the comments from the industry, understands the concerns raised, and has made changes to the footnote to balance the various industry concerns while assuring BES reliability.

The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. This is limited by two conditions: >90% demand level and 50 MW. The >90% demand level was selected to ensure that the number of hours with exposure to demand loss was not unlimited. A 90% demand level is a reasonably stressed case for most systems and the number of hours when peak demands are >90% is a small percentage of the time for most systems. A large percentage of the transmission lines that directly serve distribution customers are 161 kV or lower voltages. Ten percent (10%) of the demand on a high capacity 161 kV transmission line is approximately 50 MW.

A 4th bullet has also been added to clarify that it is acceptable to use Interruptible demand and Demand-Side Management.

The second paragraph of the footnote has been clarified and references Firm Transfers now instead of Firm Transmission Service.

b) No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Rodney Phillips	Allegheny Power	1	Negative	Allegheny Power believes the loss of non-consequential load and/or curtailment of transmission service for N-1 contingencies should be limited to only extreme circumstances. Exception 2 of footnote b allows for the loss of non-consequential load for N-1

Voter	Entity	Segment	Vote	Comment
				contingencies with no restriction. Allegheny Power recommends removing exception 2 footnote b.
Response: The SDT and the majority of the commenters disagree with this suggestion.				
Gordon Rawlings	BC Transmission Corporation	1	Negative	BCTC appreciates the good work of the SAR committee in drafting the changes to Footnote b of Table 1. BCTC agrees with the drafting team that interruption of firm load, served by either radial circuits or circuits that have became radial as a result of the contingency, should be allowed for N-1 contingencies. However, it is our position that interruption of firm load should not be limited only to such consequential loads. In our view, interruption of electric supply to some local network customers in the affected area should be permissible. This inclusion will allow transmission planners to plan BCTC's regional transmission network reliably and without impacting neighbouring transmission networks.
Faramarz Amjadi	BC Transmission Corporation	2	Negative	
Hubert C. Young	South Carolina Electric & Gas Co.	3	Negative	SCE&G has significant concern with the proposed revision to TPL Table 1, Footnote B. The current Footnote B states "Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems". The phrase "without impacting the overall reliability of the interconnected transmission systems" is important to the TPL standards to ensure that ERO standards do not dictate the level of service to customers. Service to customers and load pockets is jurisdictional to State Commissions and ERO standards should not compromise this jurisdiction. SCE&G believes that any proposed revisions to Footnote B must retain the concept that planned or controlled interruption of electric supply to customers, whether they are radial or network, is allowed as long as it does not impact the overall reliability of the interconnected transmission systems. The proposed revision eliminates this concept. There seems to be a general inconsistency and maybe confusion between the terms "reliability" and "level of service".
David Frank Ronk	Consumers Energy	4	Negative	The current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the previous version of TPL-001-1. However, it still does not allow Transmission Planners to use appropriate and necessary discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should control the decision making when BES reliability is not an issue. Often, the consequences of these events are solely local in nature, requiring only minor additional loss of local load to
James B Lewis	Consumers Energy	5	Negative	

Voter	Entity	Segment	Vote	Comment
				avoid the costly major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load.
Hugh A. Owen	Public Utility District No. 1 of Chelan County	6	Negative	The interruption of a small amount of load is, under most conditions, not a risk to the reliability of the BES and is at times necessary to preserve reliability. The planned interruption of some load may be a cost effective alternative to a costly transmission project. That is a quality of service issue.
Michael Gammon	Kansas City Power & Light Co.	1	Negative	While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load.
Charles Locke	Kansas City Power & Light Co.	3	Negative	
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	
Linda Brown	San Diego Gas & Electric	1	Affirmative	As to item (1), all load served directly by a transmission element which experiences a fault will be interrupted when the faulted element is taken out of service. This is the natural relationship between the load and the transmission element. Allowing this for BES elements may encourage transmission owners to remove transmission instead of upgrading or replacing it. Consider a load supplied by two transmission lines of different capacity. If the larger line is lost due to a contingency (N-1) and the remaining smaller line overloads the transmission owner is left with several options to address the problem: (1) move load between buses, (2) upgrade the smaller line, (3) add another line, or (4) create a radial load by removing the smaller line. Number (4) may be the least expensive and allowable under TPL-002, footnote b. Item (2) may also encourage transmission owners to develop plans which make load shedding part of category B. Consider a load served by three transmission lines, a utility may decide to remove a line, instead of upgrading, in order to set up a situation where an N-1 contingency would make the bus temporarily radial. In the event of a single outage (N-1), the load bus will be temporarily radial and load can be shed at the bus.

Voter	Entity	Segment	Vote	Comment
W. R. Schoneck	Florida Power & Light Co.	3	Affirmative	I believe the language is an improvement and clarifies the intent but I believe there still should be additional language added to give an exemption in meeting this requirement if it does not make economic sense(not economically feasible) and has no real impact on the BES.
Richard J Kafka	Potomac Electric Power Co.	1	Affirmative	It is understood that this is a compliance filing issue. This is not an issue for historic PJM members, but as PJM has expanded and as a result of the merger of historic councils into RFC, I am aware that not all regions had standards equal to those of MAAC, and this has been an issue worked out between transmission planners (historic transmission owners) and their local regulators. It is ultimately a cost issue for loss of local load that does not affect the overall reliability of the interconnected BES.
Alan Gale	City of Tallahassee	5	Affirmative	TAL thanks for SDT for the tireless effort to get to this point. TAL is voting affirmative with the following comments. We accept that the loss of non-consequential load is not a desired result for N-1 contingencies. It is also not the norm in system planning or operations. The flexibility to operate the system consistent with “good utility practice” may warrant the “odd-ball” case that would require this to occur. The dropping of non-consequential load will NOT lead to BES instability, voltage collapse, or cascading outages, which is what FERC and NERC are charged with preventing. It will lead to the shedding of load in a local area only. Utilities do not drop customers lightly. If the meter isn’t turning, we are not getting paid, so we want the meter spinning. Utility power, while vital to our normal day-to-day lives and infrastructure, was never intended to be without interruption.
Brad Chase	Orlando Utilities Commission	1	Affirmative	This change raises the bar on transmission system performance. This change applies a blanket requirement upon entities that does not take into account the number of outages, probability of outages or cost to the customer. There are certain to be situations where this blanket requirement will result in increased cost to customers for no noticeable increase in reliability. OUC does agree with the concept of greater clarification on this requirement, however this clarification may raise the bar to far by trying to establish a blanket requirement. Duke, Progress Energy and others will be submitting comments with proposed language that attempt to address some of these issues and we encourage the drafting team to consider those comments.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate				

Voter	Entity	Segment	Vote	Comment
				constraints. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Eric Egge	Black Hills Corp	1	Negative	Black Hills believes that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td>Chifong L. Thomas</td><td>Pacific Gas and Electric Company</td><td>1</td><td>Negative</td><td>PG&E commends the SDT for developing the proposed footnote b. While it is a great improvement over the complete prohibition on loss of non-consequential load for any single contingency, the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system, especially where the impact is local in nature, to avoid instability, cascading or uncontrolled separation. Such planned interruption of load may be a reasonable alternative to the environmental impacts or prohibitive costs associated with a major new transmission project. Given the potential impacts of the proposed modification, further vetting of the issues is needed. PG&E believes that NERC should be allowed to hold a public technical conference, as described in NERC’s April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.</td></tr>
<tr><td>Thomas J. Bradish</td><td>RRI Energy</td><td>5</td><td>Negative</td><td rowspan="2">RRI supports the WECC position on this issue; namely, that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC’s April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.</td></tr>
<tr><td>Trent Carlson</td><td>RRI Energy</td><td>6</td><td>Negative</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
John Tolo	Tucson Electric Power Co.	1	Negative	The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project.
James Tucker	Deseret Power	1	Negative	The prohibition of loss of non-consequential load for events resulting the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Louise McCarren	Western Electricity Coordinating Council	10	Negative	The proposed revisions to footnote b of Table 1 are an improvement to the recently balloted prohibition on loss of non-consequential load for single contingencies. The recognition of the new term "temporarily radial" is a step in the right direction. However, the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their

Voter	Entity	Segment	Vote	Comment
				individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
William Mitchell Chamberlain	California Energy Commission	9	Negative	While the proposed revisions to footnote b are an improvement to the prohibition on loss of non-consequential load for a single contingency proposed in the recently failed TPL-001-1 ballot, the prohibition of loss of non-consequential load for events resulting the loss of a single element still inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
John Mick	Colorado Springs Utilities	6	Negative	Colorado Springs Utilities ballot on the proposed changes to TPL Table 1, footnote b directed in FERC Order RM06-16-009 Colorado Springs Utilities wishes to vote NO on the proposed changes to TPL Table 1, footnote b, directed in FERC Order RM06-16-009. CSU concurs with the WECC position paper for the ballot, and agrees with the WECC statement "that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues".

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

Voter	Entity	Segment	Vote	Comment
The SDT agrees that a technical conference on this issue would be of value. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
Horace Stephen Williamson	Southern Company Services, Inc.	1	Negative	Comments have already been submitted previously, but it will be added here again. Proposed footnote should read... No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers when coupled with the appropriate re-dispatch of resources obligated to re-dispatch. It must be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. The proposed changes are based on the
Richard J. Mandes	Alabama Power Company	3	Negative	
Anthony L Wilson	Georgia Power Company	3	Negative	

Voter	Entity	Segment	Vote	Comment
Gwen S Frazier	Gulf Power Company	3	Negative	following... "The proposed wording by the drafting team seems to imply that the curtailment of firm transmission service is permitted to address single contingency constraints if coupled with the redispatch of network resources. The original language stated only that curtailments were permitted to prepare for the next contingency, not to address loading related to the initial contingency. The proposed wording could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint. Southern Companies recommend that the original language relating to "preparing for the next contingency" be incorporated into the drafting team's proposal."
Don Horsley	Mississippi Power	3	Negative	
Michael Ibold	Xcel Energy, Inc.	3	Negative	The proposed modification to footnote b of Table I in TPL-001 - 004 standards states that after a Category B contingency, there should not be any thermal, voltage or stability violation, no interruption of firm load (except the load that is directly connected to the elements that are removed from service as a result of the contingency) and no firm transfer curtailment (except when coupled with re-dispatch of resources obligated to re-dispatch). We believe the proposed footnote b creates a gap between TPL-002 and TPL-003 standards, since it does not address conditions when firm load shedding and firm transfer curtailments are not required to meet the system performance for Category B contingency, but one or both are the required system adjustments to prepare for the next contingency (Category C3). When firm transfer is curtailed after the first contingency in preparation for the next contingency, it is not clear from the proposed footnote b if this is considered a valid system adjustment for Category C or a violation of Category B. Recall that the existing footnote b addresses this condition explicitly by stating "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm Transfers."
Liam Noailles	Xcel Energy, Inc.	5	Negative	
David F. Lemmons	Xcel Energy, Inc.	6	Negative	
George T. Ballew	Tennessee Valley Authority	5	Affirmative	TVA appreciates the work of the SDT on this issue. However, TVA recommends revising the second paragraph of the revised footnote b: "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. However, curtailment of Firm Transmission Service is only allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility
Marjorie S. Parsons	Tennessee Valley Authority	6	Affirmative	

Voter	Entity	Segment	Vote	Comment
				Ratings in those regions should also be respected.” Without the changes in the first two sentences above, the proposed wording by the SDT could be interpreted to allow re-dispatch/firm curtailments to address any single contingency constraint instead of in preparation for the next contingency.
Larry Akens	Tennessee Valley Authority	1	Affirmative	TVA appreciates the work of the SDT. However, TVA recommends revising the second paragraph of the revised footnote "b". Without changes in the first two sentences, the proposed wording by the SDT could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint instead of in preparation for the next contingency.

Response: The SDT believes that System re-dispatch is an acceptable System adjustment to “remain within applicable Facility Ratings” to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote ‘b’ clarifies that re-dispatch is allowable to “remain within” ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can be only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the Firm Transmission Service cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words “To prepare for the next Contingency” to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
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~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Robert W. Roddy	Dairyland Power Coop.	1	Negative	DPC CONCURS WITH THE MRO COMMENTS.
Jason Shaver	American Transmission Company, LLC	1	Affirmative	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed if the tripping of the load is either accepted or volunteered by the customer.
Lawrence R. Larson	Otter Tail Power Company	1	Negative	The change precludes the use of direct load control systems that should be allowed to relieve transmission problems. These systems control firm transmission load but rate conditions can allow their use to mitigate transmission problems.

Response: *(Note - MRO did not submit comments with the initial ballot – but did submit the following comment during the formal comment period: For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.)*

The SDT has added the fourth bullet to address your concern.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

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<table>
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<tr><td>Ajay Garg</td><td>Hydro One Networks, Inc.</td><td>1</td><td>Negative</td><td rowspan="2">Hydro One is casting a negative vote for the following reasons:

1. The amendment to the footnote does not add any technical value to the standard. It was added only to satisfy a FERC directive to address comments made to allow non-consequential load loss after a single contingency event, “based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios.”

2. Addressing curtailment of Firm Transmission Service with re-dispatch of resources is a matter of a commercial nature and should be dealt with in the agreements dealing with such services. Issues of contracted transmission services, firm or otherwise, are not a reliability related matter and are not to be dealt with in this standard.

3. Matters of interruption of firm load should be incorporated into this standard only after the FERC NOPR on the definition of the BES is resolved. As it stands, the footnote will pose significant problems if the 100 kV and above FERC proposal is applied across the board, unless the standard specifically states that it applies to the BES as defined by the region (current definition).</td></tr>
<tr><td>Michael D. Penstone</td><td>Hydro One Networks, Inc.</td><td>3</td><td>Negative</td></tr>
<tr><td colspan="5">Response: 1. & 2. The SDT disagrees – there is a direct impact on reliability of the BES associated with these concerns. The SDT has added clarity to the footnote by designating constraints for Demand and firm transfer curtailment.

3. The SDT disagrees that this needs to wait on the FERC NOPR. This standard is applicable to the BES as it is defined.</td></tr>
<tr><td>Spencer Tacke</td><td>Modesto Irrigation District</td><td>4</td><td>Negative</td><td>I am voting NO vote because of the lack of clarity of the second paragraph of the proposed change. Although paragraph 1 is an improvement to the current wording, and actually allows for some specific flexibility in shedding load for an N-1 event, the lack of clarity in the second paragraph could lead to varied interpretations by members and compliance auditors. Thank you.</td></tr>
<tr><td colspan="5">Response: The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

b)–No interruption of <s>firm Load</s> projected customer Demand is allowed except:</td></tr>
</table>

<table>
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</td></tr>
<tr><td>Dana Cabbell</td><td>Southern California Edison Co.</td><td>1</td><td>Negative</td><td rowspan="3">It is SCE's position that the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. When planned load interruption is identified as a response to a single event, the impact to the system is often local in nature. The planned interruption of load may be a desirable alternative to the prohibitive costs associated with a major new transmission project.

If the NERC Standards Drafting Team decides to proceed with footnote B, as written, it needs to ensure that Transmission Owners, Transmission Operators, and Transmission Planners have enough time to both design and implement any mitigation plans necessary to be compliant with the new language. In almost all cases the actual implementation of a solution requiring new construction will be dependent on a number of different regulatory agencies providing the necessary permits allowing for its construction. As such, NERC needs to ensure that any time frame associated with compliance to the proposed language be variable, and allow for extended implementation time frames based on system conditions that may delay placing mitigation plans in service. An example of a reasonable variable time frame to be compliant with the proposed language in footnote B would be to start the clock 60 months from receiving the pertinent environmental permitting. In</td></tr>
<tr><td>David Schiada</td><td>Southern California Edison Co.</td><td>3</td><td>Negative</td></tr>
<tr><td>Ahmad Sanati</td><td>South California Edison Company</td><td>5</td><td>Negative</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
				California this could be the issuance of a Draft Environmental Impact Review pursuant to the California Environmental Quality Act.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

The SDT has added more latitude for the Transmission Planner with the addition of the 3rd bullet and believes that 60 months should be sufficient.

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Voter	Entity	Segment	Vote	Comment
Henry Ernst-Jr	Duke Energy Carolina	3	Negative	On the initial ballot of TPL-001-1 Duke Energy also voted “Negative”, primarily because Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We also sought rehearing on the Commission’s March 18 Order Setting Deadline for Compliance (Docket No. RM06-16), with respect to this and other issues. We believe that FERC’s directive in that Order to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for “reliable operation” of the bulk-power system to prevent “instability, uncontrolled separation or cascading failures,” none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission’s directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission’s reach beyond its review of measures that are needed for “reliable operation” of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission’s jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the potential impacts (environmental, historical, archaeological, aesthetic...) of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. With this “Negative” vote, Duke offers the following ideas on alternatives for the SDT to consider that will allow for appropriate discretion and facilitate proper planning while allowing non-consequential load loss (NCLL). The standard should allow for dropping of limited amounts of non-consequential load in situations where it would be reasonable for a bounded time period and under restricted system conditions (e.g. 1-3 years only when load is >90 % of peak conditions). Dropping of non-consequential load would be prudent planning in situations where the near term impact of load projections or implementation of nearby transmission/generation projects will alleviate the necessity of an upgrade to meet N-1 conditions. Also, reliability of service to end-use customer is impacted by the entire system

Voter	Entity	Segment	Vote	Comment
				from source to load. Where allowance for NCLL would not greatly impact individual end-use customers' level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to avoid projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics (e.g. SAIFI/SAIDI/ASAI) should also be considered by the SDT for determination of acceptable use of NCLL.
Luther E. Fair	Gainesville Regional Utilities	1	Affirmative	Even though I am voting in the affirmative, I agree that most of the comments offered by Duke and Norther Indiana in their earlier statements have merit and should be considered. Also, I believe that the use of reliability metrics should be considered by the SDT for determination of acceptable use of NCLL.
Mace Hunter	Lakeland Electric	3	Negative	Reliability should consider the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customer's level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to delay projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics should also be considered by the SDT for determination of acceptable use of NCLL.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

The SDT discussed the use of reliability metrics for providing flexibility to planners but has not included their use as this would make the implementation too complex.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

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				o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Sammy Roberts	Progress Energy Carolinas	1	Negative	Progress Energy applauds NERC's efforts to improve the footnote (b) language with respect to conditional allowance of curtailing Firm Transmission Service, which is addressed in the second paragraph of the proposed new footnote (b). PE remains concerned, however, that the first paragraph of the proposed new footnote (b) does not allow for curtailment of non-radial non-consequential load. The ability to curtail non-consequential load in the planning horizon can be a useful tool to mitigate local area issues, and has not been detrimental to the Bulk Electric System (BES). Disallowing the curtailment of non-radial non-consequential load essentially prohibits taking action in situations in which the load in question is clearly at a localized self-contained level of the system, i.e. the distribution system(s) served by the Transmission Owner. Prohibiting the curtailment of local load thus constitutes regulating distribution feeder reliability rather than BES reliability. Events that could be mitigated through the curtailment of local, non-radial non-consequential load are infrequent, and such curtailment has no material effect on the reliability of the BES. PE therefore suggests that the following addition (item (3)) to the first paragraph of the proposed footnote (b) be considered: "No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, and/or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities, and/or (3) Planned or controlled interruption of any additional Load required to mitigate the post-contingency results, provided that the non-
Lee Schuster	Florida Power Corporation	3	Negative	
Sam Waters	Progress Energy Carolinas	3	Negative	
Wayne	Progress Energy	5	Negative	

Voter	Entity	Segment	Vote	Comment
Lewis	Carolinas			consequential load being shed for the event is localized, and provided that the total load shed for the event does not exceed 2% of the Planned system peak demand or 200 MW, whichever value is less.”
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT did adopt a limit but felt that 2% of system peak or 200 MW was not equitable for all entities. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
Timothy VanBlaricom	California ISO	2	Negative	The California ISO supports NERC’s request for a public technical conference to be held, as described in NERC’s April 19, 2010 request for rehearing and motion for stay of the March 18 Order (RM06-16-009), to provide the opportunity to gain industry input and written comments regarding the Commission’s TPL-002-0 directive for NERC to develop a modification to the TPL-002-0 Table 1 footnote b.
Response: The SDT agrees that a technical conference would be of value.				

Voter	Entity	Segment	Vote	Comment
Terry L. Blackwell	Santee Cooper	1	Negative	The Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning processes appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. Table B footnote still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, and local customers should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. The Commission's directive sets forth an expectation that NERC is to implement standards that address all loss of load at costs that may not be commensurate with bulk power system reliability, as statutorily defined, which is fundamentally different from what the Reliability Standards were intended to do.
Zack Dusenbury	Santee Cooper	3	Negative	
Suzanne Ritter	Santee Cooper	6	Negative	
Response: The SDT is not in position to comment on FERC's authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.				
Kimberly J. Jones	North Carolina Utilities Commission	9	Negative	The NC Utilities Commission is concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1, and as explained in draft footnote b, is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions. This requirement does not provide any benefit to reliability of the bulk electric system and could undermine state efforts to balance reliability issues with cost of service issues. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load, understanding that state commissions are positioned to force electric utilities to address local service quality issues on an expedited basis, should it be necessary and in the public interest.
Response: The SDT understands the concern but believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.				

Voter	Entity	Segment	Vote	Comment
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Negative	THE PROPOSED INTERPRETATION WILL UNDERMINE THE INTERNATIONAL STANDARDS SETTING PROCESS AND COULD RESULT IN DIFFERING INTERPRETATIONS OF STANDARDS ON THE NORTH AMERICAN BULK-POWER SYSTEM.
Response: The SDT disagrees and believes that the footnote has been clarified appropriately within the standards development process.				
Daryn Barker	Louisville Gas and Electric Co.	6	Negative	The revised footnote b on Table 1 imposes additional requirements on the responsible entities. The footnote states: Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. However, R1 states: The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned These statements address different and inconsistent scope. If the change in scope was intended then a change should also be made to R1 to reconcile the inconsistency.
Charlie Martin	Louisville Gas and Electric Co.	5	Negative	Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. However, R1 states: The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned These statements address different and inconsistent scope. If the change in scope was intended then a change should also be made to R1 to reconcile the inconsistency.
Response: The SDT agrees that your assessment is for your portion of the interconnected grid. However, when performance in one system is dependent on generation dispatch in another system or vice versa, the SDT believes that one must ensure that the re-dispatch is feasible. The SDT does not believe that this presents a conflict with Requirement R1.				
John Apperson	PacifiCorp	3	Negative	This proposal warrants a “no” vote due to the current uncertainty regarding the outcome of the FERC TPL-002 NOPR issued by FERC on March 18, 2010. The impacts of the proposed changes to footnote B cannot be assessed separately from the alternative interpretation of TPL-002 proposed by FERC. The proper planning of a transmission system requires that all performance requirements are known and understood. If only some of the requirements are known and understood it is impossible to properly plan, study, assess, and operate the transmission system.

Voter	Entity	Segment	Vote	Comment
Response: The current TPL-002 is in force and will remain so until the completion of the cited FERC NOPR. This limited scope revision to footnote 'b' is to add clarity to what is in effect.				
Keith V. Carman	Tri-State G & T Association Inc.	1	Negative	Tri-State does believe that the new footnote is an improvement, but thinks there are still some changes necessary. We believe that the word "only" should be removed from the phrase "...where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities" because that discrimination was not required in FERC Order RM-06-16-009. There may be times when facilities near the temporary radial facilities might fall outside the limits set in reliability criteria but the situation is mitigated if the load shedding occurs at the radial facility. The meaning of the second paragraph of the new footnote is unclear. Tri-State recommends changing it to "Curtailment of Firm Transmission Service is not allowed unless it is coupled with curtailment-offsetting resources that are obligated to re-dispatch. Further, the curtailment activities cannot result in the shedding of any Firm load or in violations of Facility Ratings, either internal or external to the planning region." We believe that FERC's directive in FERC Order RM-06-16-009 to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. Instead of removing the word 'only', the 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.				

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Claudiu Cadar	GDS Associates, Inc.	1	Negative	We do not agree with the proposed changes due to several reasons. Although the proposed change will directly influence the reliability standards and transmission system performances, will also have an indirect impact on the economic side with respect to the expansion of existing transmission system. We believe that FERC directive as stipulated in Order 693 cannot constrict, nor impose certain actions outside of the reliability limits. We believe that since these events are merely isolated and rarely enforced, the decision of mandating a great financial effort as a consequence of the proposed changes would certainly be counterbalanced by its feasibility when compare with the current cost of load shedding. While the revised footnote b can be certainly considered an improvement from the current version, however it still does not allow the joined entities involved to have power over the decision making when BES reliability is not an issue. We also believe that any mandatory changes implemented in the TPL standards under the current scenario are not entirely feasible unless all other issues such as the definition of the

Voter	Entity	Segment	Vote	Comment
				BES, Consequential / Non-consequential Load, BES Critical Element, etc gets resolve ahead. The revision with respect to load shedding, specifically the portion about shedding loads on newly radial facilities, does not match the version 1 TPL standard definition of consequential load loss. To approve the proposed revision to footnote 'b' would create an unnecessary discrepancy between the version 1 TPL standard under consideration and the existing standards. We recognize that the Version 1 will replace Version 0, but since it appears that the performance standard with respect to footnote 'b' is intended to be same in the revised footnote and the Version 1 standard, it only makes sense that the revised version 0 footnote 'b' match the consequential load loss definition contemplated in Version 1. In the light of the above we suggest the Commission to approach different other solutions and ideas for improving the current reliability of the transmission system without enforcing decisions beyond its statutory scope. We advance an alternative to this matter meant to balance the reliability of the transmission system and its indirect financial impact. Although the solution that we offer would require an extended time for development and implementation, however we urge NERC to consider it in its further approach. Our alternative consists mainly in implementing an additional term such as "Critical Load" which we have briefly figured that would consist in particular load necessary to be maintained in service without interruption. Even though this new term would seemed to be at first related with the quality of the service, however a joint association of transmission planners, customers, regulatory entities as decision makers can simply individualize the load that cannot be shed, as well as future transmission improvements that will be required to serve this envisioned small amount of load rather than the entire load. In this way we will create a reasonable balance in between the reliability of the transmission system and the cost to maintain / improve this reliability.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~

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Ronald D. Schellberg	Idaho Power Company	1	Negative	While the proposed revisions are an improvement to the prohibition on loss of non-consequential load for a single contingency proposed in the recently failed TPL-001-1 ballot, that the prohibition of loss of non-consequential load for events resulting the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. However, the removal of: "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." will require significant adjustments in either TRM or TTC reductions to be compliant with this revised standard in the WECC Region. To construct additional transmission facilities to maintain present day business could easily exceed 10 Billion dollars throughout the WECC region. For example, the Pacific AC Intertie currently has a TTC of 4800 MW spread across 3 500 kV transmission lines. With the loss of one Transmission line, the Pacific AC intertie drops to 3200 MW. Removal of this sentence would require TP either to drop the Firm TTC of the Intertie to 3200, or include a TRM reservation of at least 1600 MW. The TPs would not be able to say that a loss of 1600 MW of import capacity would not result in curtailments of firm load. Just about all multi

Voter	Entity	Segment	Vote	Comment
				transmission line paths in the WECC Region would suffer. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. In the case of long interties between subregions of WECC, these interties have never been planned to operate in this manner. Idaho Power recommends that the sentence permiting system adjustments be reinserted into Footnote B.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

The SDT believes that System re-dispatch is an acceptable System adjustment to "remain within applicable Facility Ratings" to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can be only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the Firm Transmission Service cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

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- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td colspan="5">o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.</td></tr>
<tr><td>Francis J. Halpin</td><td>Bonneville Power Administration</td><td>5</td><td>Affirmative</td><td>For consistency, regarding the firm transfer issue, the term "Firm Transmission Service" should be replaced with "Firm Transfers" in order to be consistent with the fourth column of the existing Table 1 "Transmission System Standards - Normal and Emergency Conditions".</td></tr>
<tr><td colspan="5">**Response:** The SDT agrees and has made the change.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~

o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~

o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW

o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.</td></tr>
<tr><td>Kim Warren</td><td>Independent Electricity System Operator</td><td>2</td><td>Affirmative</td><td>IESO supports the revisions made to footnote 'b' based on the present definitions of BES and Firm Demand and on the understanding that the NERC standards apply only to the BES as defined in the NERC Glossary as follows: "As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighbouring systems, and associated equipment, generally operated at voltages of 100 kV</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
				or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." To be clear, our interpretation of the present definition of BES is that it defers to each Regional Reliability Organization to define the elements of the power system that are considered BES and, therefore in the NPCC Region, "BES as defined by NERC" = "BPS as defined by NPCC".
Response: The SDT agrees that the standard applies to the BES as defined in the Glossary.				
Jacquie Smith	ReliabilityFirst Corporation	10	Affirmative	If this revision is an urgent action, then the implementation timeframe should be shorter. In the clarification paragraph below, I do not understand the first sentence. Are there commas missing? What is the requirement and what is the exception? Also, I question the validity of using "should" in the second sentence. If it is a requirement, then it needs to be stated as a requirement. If it is a suggestion, then it does not belong in the standard. No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.
Response: This has not been classified as an 'urgent action'. Commas have been added as appropriate and a re-wording was made which should make this clear. 'Should' has been replaced by 'would' to provide additional clarity. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels				

Voter	Entity	Segment	Vote	Comment
				greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
David H. Boguslawski	Northeast Utilities	1	Affirmative	Northeast Utilities (NU) believes the language of the proposed revision to footnote 'b' can be better defined as the proposed revision is subject to interpretation by the different entities and regulatory agencies. Future conflicts can be minimized by further clarifying the proposed revision. Also, NU is concerned that this new modification does not specify the amount of permissible load shed nor does it require the planning entity to minimize load shedding under this exception.

Response: The SDT has made several clarifying changes to the footnote which should alleviate your concerns.

The SDT has modified the footnote for clarity and added constraints in new bullet 3 to address your specific concern.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Donald S. Watkins	Bonneville Power Administration	1	Affirmative	On the firm transfer issues, the term "Firm Transmission Service" should be replaced with "Firm Transfers" to be consistent with the fourth column of the existing Table 1 Transmission System Standards - Normal and Emergency Conditions.
Rebecca Berdahl	Bonneville Power Administration	3	Affirmative	
Brenda S. Anderson	Bonneville Power Administration	6	Affirmative	

Response: The SDT agrees and has made this change.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Frank Gaffney	Florida Municipal Power Agency	4	Affirmative	Please see FMPA comments submitted through the concurrent comment period for Project 2010-11
David Schumann	Florida Municipal Power Agency	5	Affirmative	

Voter	Entity	Segment	Vote	Comment
Response: Please see the response to FMPA comments above.				
Carter B Edge	SERC Reliability Corporation	10	Affirmative	The footnote makes clearer when load can be dropped for planning purposes. By making this footnote more specific, it supports reliability and helps stakeholders apply the TPL standards.
Timothy Beyrle	City of New Smyrna Beach Utilities Commission	4	Affirmative	This is an area of fuzziness between State jurisdiction and Federal jurisdiction. In all honesty, shedding load for local area impacts has nothing to do with BES reliability and should not be under FERC jurisdiction under Section 215 of the Federal Power Act, but rather State jurisdiction for quality of service issues. However, there is also the matter of FERC jurisdiction over commercial matters and the opportunity to "game" the original footnote by transmission providers by allowing firm load shedding to grant firm transmission service for themselves, thereby avoiding or deferring transmission investment, while at the same time denying or requiring others to build the same transmission avoided in order to obtain transmission service. We can see how difficult it is from a drafting team's perspective in achieving a balanced position between these different matters. The drafting team should be applauded for finding a reasonable position.
Response: Thank you for your support.				
Larry E Watt	Lakeland Electric	1	Affirmative	This issue is better handled within the development of the new TPL-001 standard.
Response: The current TPL-002 is in force and will remain so until the completion of the TPL-001-2 effort. This limited scope revision to footnote 'b' is to add clarity to what is in effect.				

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RELIABILITY CORPORATION

Consideration of Comments on Project 2010-11: TPL Table 1 Order and Comments Submitted with Initial Ballots

The Standards Committee thanks all commenters who submitted comments on the proposed SAR for the TPL Table 1 Order. The SAR proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

The SAR, implementation plan, and the clean and redline versions to the four TPL standards were posted for a 40-day public comment period from April 15, 2010 through May 27, 2010. Stakeholders were asked to provide feedback on the standards through a special electronic comment form. There were 22 sets of comments, including comments from more than 80 different people from approximately 40 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

The initial ballot for the proposed changes to the four TPL standards was conducted from May 17-27, 2010. The comments submitted with initial ballots and the drafting team's responses to those comments are contained in this report.

All comments submitted during the comment period and the initial ballot results are posted on the following page:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Based on stakeholder comments, the drafting team has made some additional changes to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT from the cited inputs that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when load could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand is appropriate in certain limited circumstances and that such usage is not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand were not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that requires ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in the 2nd posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote 'b' to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

The above changes will be noted to stakeholders in a separate posting before the initiation of another ballot.

The revised Footnote ‘b’ is:

b) An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- Demand that is directly served by the elements that are removed from service as a result of the Contingency

- Interruptible Demand or Demand-Side Management

- Demand that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected.

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

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

Comments and Responses from Formal Comment Period:

Comments and Responses from Initial Ballot:

The Industry Segments are:

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

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
4.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
5.	Sylvain Clermont	Hydro-Quebec TransEnergie		1
6.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
7.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
8.	Ben Eng	New York Power Authority	NPCC	4
9.	Brian Evans-Mongeon	Utility Services	NPCC	8
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
15.	Randy MacDonald		New Brunswick System Operator	NPCC					2				
16.	Bruce Metruck		New York Power Authority	NPCC					6				
17.	Lee Pedowicz		Northeast Power Coordinating Council	NPCC					10				
18.	Robert Pellegrini		The United Illuminating Company	NPCC					1				
19.	Saurabh Saksena		National Grid	NPCC					1				
20.	Michael Schiavone		National Grid	NPCC					1				
2.	Group	Philip R. Kleckley	South Carolina Electric & Gas	X		X		X					
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Bob Jones		Southern Company Services - Trans.	SERC					1				
2.	David Marler		Tennessee Valley Authority	SERC					1				
3.	Charles Long		Entergy	SERC					1				
4.	James Manning		North Carolina Electric Membership Corporation	SERC					3				
5.	Pat Huntley		SERC Reliability Corporation	SERC					10				
3.	Group	John Bee	Exelon Transmission Strategy & Compliance	X		X		X					
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Mortenson, Eric		:(ComEd)	RFC					1				
2.	Weaver, David W		(PECO)	RFC					1				
3.	McHugh, Kathleen P		(PECO)	RFC					1				
4.	Kay, Thomas W		(ComEd)	RFC					1				
5.	Szymczak, Ronald		(ComEd)	RFC					1				
6.	Chu, Ron F		(PECO)	RFC					1				
7.	Donnelly, Michael J		(PECO)	RFC					1				
8.	Kliros, Chris B		(ComEd)	RFC					1				
9.	Mills, Paul M		(ComEd)	RFC					1				
10.	Webb, Becky		(ComEd)	RFC					1				
4.	Group	Denise Koehn	BPA, Transmission Reliability Program	X		X		X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Chuck Matthews		BPA, Transmission Planning	WECC					1				
2.	Berhanu Tesema		BPA, Transmission Planning	WECC					1				
3.	Larry Furumasu		BPA, Transmission Planning	WECC					1				
4.	Kyle Kohne		BPA, Transmission Planning	WECC					1				
5.	Don Watkins		BPA, Transmission System Operations	WECC					1				
6.	Rebecca Berdahl		BPA, Power, Long Term Sales and Purchases	WECC					3				
5.	Group	Carol Gerou	Midwest Reliability Organization										X
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Chuck Lawrence		American Transmission Company	MRO					1				
2.	Tom Webb		Wisconsin Public Service	MRO					3, 4, 5, 6				
3.	Terry Bilke		Midwest ISO Inc.	MRO					2				
4.	Jodi Jenson		Western Area Power Administration	MRO					1, 6				
5.	Ken Goldsmith		Alliant Energy	MRO					4				
6.	Dave Rudolph		Basin Electric Power Cooperative	MRO					1, 3, 5, 6				
7.	Eric Ruskamp		Lincoln Electric System	MRO					1, 3, 5, 6				
8.	Joseph Knight		Great River Energy	MRO					1, 3, 5, 6				
9.	Joe DePoorter		Madison Gas & Electric	MRO					3, 4, 5, 6				
10.	Scott Nickels		Rochester Public Utilities	MRO					4				
11.	Terry Harbour		MidAmerican Energy Company	MRO					1, 3, 5, 6				
6.	Group	Richard Kafka	Pepco Holdings, Inc.	X		X		X	X				
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Jim Summers		Delmarva Power and Light Co.	RFC					1				
2.	John Radman		Potomac Electric Power Company	RFC					1				
7.	Group	Ben Li	IESO		X								
	Additional Member		Additional Organization	Region					Segment Selection				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Bill Phillips		MISO	MRO									
2.	James Castle		NYISO	NPCC									
3.	Charles Yeung		SPP	SPP									
4.	Lourdes Estrada-Salinero		CAISO	WECC									
5.	Patrick Brown		PJM	RFC									
6.	Steve Myers		ERCOT	ERCOT									
8.	Group	Frank Gaffney	Florida Municipal Power Agency	X			X	X	X				
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Timothy Beyrle		Utilities Commission of New Smyrna Beach	FRCC					4				
2.	Greg Woessner		Kissimmee Utility Authority	FRCC					1				
3.	Jim Howard		Lakeland Electric	FRCC					1				
4.	Lynne Mila		City of Clewiston	FRCC					3				
5.	Joe Stonecipher		Beaches Energy Services	FRCC					1				
6.	Cairo Vanegas		Fort Pierce Utility Authority	FRCC					4				
9.	Individual	Stephen Mizelle	Southern Company Transmission	X									
10.	Individual	Robert Casey	Georgia Transmission Corporation (Bulk System Planning)	X									
11.	Individual	Thad Ness	American Electric Power	X		X		X	X				
12.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
13.	Individual	Martin Bauer	US Bureau of Reclamation					X					
14.	Individual	Kirit Shah	Ameren	X		X		X	X				
15.	Individual	Robert W. Roddy	Dairyland Power Cooperative	X		X		X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
16.	Individual	Marty Berland	Progress Energy	X		X		X	X				
17.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
18.	Individual	Charles Lawrence	American Transmission Company	X									
19.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
20.	Individual	Bill Middaugh	Tri-State Generation and Transmission Association, Inc.	X		X		X	X				
21.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
22.	Individual	Dan Rochester	Independent Electricity System Operator		X								

1. The SDT is proposing a revision to footnote 'b' in the TPL tables to comply with FERC Order RM-06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.

Summary Consideration: The SDT has listened to the comments from the industry, understands the concerns raised, and has made changes to the footnote to balance the various industry concerns while assuring BES reliability.

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT from the cited inputs that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when load could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in this 2nd posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote 'b' to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial~~

~~Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Duke Energy	No	Duke Energy voted "Negative" on the initial and current ballots of TPL-001-1, primarily because Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We also sought rehearing on the Commission's March 18 Order Setting Deadline for Compliance (Docket No. RM06-16), with respect to this and other issues. We believe that FERC's directive in that Order to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the potential impacts (environmental, historical, archaeological, aesthetic...) of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. Duke offers the following ideas on alternatives for the SDT to consider that will allow for appropriate discretion and facilitate proper planning while allowing non-consequential load loss (NCLL).The standard should allow for dropping of limited amounts of non-consequential load in situations where it would be reasonable for a

Organization	Yes or No	Question 1 Comment
		bounded time period and under restricted system conditions (e.g. 1-3 years only when load is >90 % of peak conditions). Dropping of non-consequential load would be prudent planning in situations where the near term impact of load projections or implementation of nearby transmission/generation projects will alleviate the necessity of an upgrade to meet N-1 conditions. Also, reliability of service to end-use customer is impacted by the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customers' level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to avoid projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics (e.g. SAIFI/SAIDI/ASAI) should also be considered by the SDT for determination of acceptable use of NCLL.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Midwest Reliability Organization	No	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by

Organization	Yes or No	Question 1 Comment
		the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
Dairyland Power Cooperative	No	DPC concurs with the MRO comments: For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
American Transmission Company	No	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.

Response: The SDT has added the second bullet to address your concern.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

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- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

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Organization	Yes or No	Question 1 Comment
Georgia Transmission Corporation (Bulk System Planning)	No	Georgia Transmission Corporation (GTC) believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We believe that FERC's directive in (Docket No. RM06-16) to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. We also note that on April 19 NERC filed a request for rehearing with FERC asking that the Commission revise the directive in Paragraph 8 of the March 18 TPL-002 Order to allow NERC the necessary time to incorporate changes to the TPL-002 Reliability Standard through the Reliability Standards Development Process that are necessary to achieve bulk power system reliability. NERC also requested that the Commission grant NERC's Motion for Stay to stay the Order so that a public technical conference with opportunity for comment can be held in order to provide parties an opportunity to meet and discuss the technical considerations of developing a modification to the TPL-002 standard that prohibits the loss of non-consequential firm load in the event of an N-1 contingency. NERC's April 19 filing pointed out that if the Commission's directive to disallow the loss of non-consequential firm load for an N-1 contingency is implemented, a question is presented regarding whether the Reliability Standard still serves the purpose of ensuring the Reliable Operation of the bulk power system by preventing instability, uncontrolled separation, and cascading failures. That is, the Commission's directive sets forth an expectation that NERC is to implement standards that address all loss of load at costs that may not be commensurate with bulk power system reliability, as statutorily defined, which is fundamentally different from what the Reliability Standards were intended to do.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the		

Organization	Yes or No	Question 1 Comment
various industry concerns while assuring BES reliability. . Footnote ‘b’ now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Progress Energy	No	Progress Energy applauds NERC’s efforts to improve the footnote (b) language with respect to conditional allowance of curtailing Firm Transmission Service, which is addressed in the second paragraph of the proposed new footnote (b). PE remains concerned, however, that the first paragraph of the proposed new footnote (b) does not allow for curtailment of non-radial non-consequential load. The ability to curtail non-consequential load in the planning horizon can be a useful tool to mitigate local area issues, and has not been detrimental to the Bulk Electric System (BES). Disallowing the curtailment of non-radial non-consequential load essentially prohibits taking action in situations in which the load in question is clearly at a localized self-contained level of the system, i.e. the distribution system(s) served by the Transmission Owner/Operator. Prohibiting the curtailment of local load thus constitutes regulating distribution feeder reliability rather than BES reliability. Events that could be mitigated through the curtailment of local, non-radial non-consequential load are infrequent, and such curtailment has no material effect on the reliability of the BES.

Organization	Yes or No	Question 1 Comment
		PE therefore suggests that the following addition (item (3)) to the first paragraph of the proposed footnote (b) be considered:"No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, and/or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities, and/or (3) Planned or controlled interruption of any additional Load required to mitigate the post-contingency results, provided that the non-consequential load being shed for the event is localized, and provided that the total load shed for the event does not exceed 2% of the Planned system peak demand or 200 MW, whichever value is less."

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The SDT did not adopt numerical limits as a single nation-wide value was not seen as equitable for all entities.

Footnote 'b' now reads:

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- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

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Organization	Yes or No	Question 1 Comment
Hydro-Québec TransEnergie	No	The proposed changes do not adequately address FERC's concerns in RM06-16-009. The Commission

Organization	Yes or No	Question 1 Comment
(HQT)		again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." The proposed changes to footnote 'b' indicate "No interruption of firm Load is allowed except:... (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities." The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as "the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency." In referencing Order 693, the Commission reiterated its position that TPL standards "should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." "Must" should be used instead of "should" in the last sentence of the footnote, making it to read "Facility Ratings in those regions must also be respected."
Northeast Power Coordinating Council	No	The proposed changes do not adequately address FERC's concerns in RM06-16-009. The Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." The proposed changes to footnote 'b' indicate "No interruption of firm Load is allowed except:... (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities." The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as "the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency." In referencing Order 693, the Commission reiterated its position that TPL standards "should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." "Must" should be used instead of "should" in the last sentence of the footnote, making it to read "Facility Ratings in those regions must also be respected."
Response: The SDT believes that it has been responsive to the FERC directive in that the standards development process has been employed. In the development of the footnote, the SDT has balanced the need for discretion while addressing local area concerns with the need to assure the reliability of the BES.		

Organization	Yes or No	Question 1 Comment
‘Must’ is not appropriate in a footnote as it would impose a requirement in the footnote. The SDT has replaced ‘should’ with ‘would’ to correct the grammar. Footnote ‘b’ now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Tri-State Generation and Transmission Association, Inc.	No	Tri-State does believe that the new footnote is an improvement, but thinks there are still some changes necessary. We believe that the word “only” should be removed from the phrase “...where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities” because that discrimination was not required in FERC Order RM-06-16-009. There may be times when facilities near the temporary radial facilities might also fall outside the limits set in reliability criteria but the situation is mitigated if the load shedding occurs at the radial facility. The meaning of the second paragraph of the new footnote is unclear. Tri-State recommends changing it to "Curtailment of Firm Transmission Service is not allowed unless it is coupled with curtailment-offsetting resources that are obligated to re-dispatch. Further, the curtailment activities cannot result in the shedding of any Firm load or in violations of Facility Ratings, either internal or external to the planning region."
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the		

Organization	Yes or No	Question 1 Comment
various industry concerns while assuring BES reliability. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others. Footnote ‘b’ now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Southern Company Transmission	No	We propose that the section in double parentheses be deleted. The proposed wording by the drafting team seems to imply that the curtailment of firm transmission service is permitted to address single contingency constraints if coupled with the redispatch of network resources. The original language stated only that curtailments were permitted to prepare for the next contingency, not to address loading related to the initial contingency. The proposed wording could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint. Southern Companies recommend that the original language relating to “preparing for the next contingency” be incorporated into the drafting team’s proposal.((Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including

Organization	Yes or No	Question 1 Comment
		curtailments of contracted Firm (non-recallable reserved) electric power Transfers.)) No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch. where it can It must be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

Response: The SDT believes that System re-dispatch is an acceptable System adjustment to "remain within applicable Facility Ratings" to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

Footnote 'b' now reads:

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South Carolina Electric & Gas	Yes	For better clarity delete the phrase "when coupled with" in the second paragraph of footnote 'b.'
Response: The SDT did not delete the suggested phrase as it believes it is correct as stated but added commas to make the phrase read more clearly. Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Independent Electricity System Operator	Yes	IESO supports the revisions made to footnote 'b' based on the present definitions of BES and Firm Demand and on the understanding that the NERC standards apply only to the BES as defined in the NERC Glossary as follows:"As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." To be clear, our interpretation of the present definition of BES is

Organization	Yes or No	Question 1 Comment
		that it defers to each Regional Reliability Organization to define the elements of the power system that are considered BES and, therefore in the NPCC Region, "BES as defined by NERC" = "BPS as defined by NPCC".
Response: The SDT agrees that the standard applies to the BES as defined in the Glossary.		
BPA, Transmission Reliability Program	Yes	On the firm transfer issues, the term "Firm Transmission Service" should be replaced with "Firm Transfers" to be consistent with the fourth column of the existing Table 1 Transmission System Standards - Normal and Emergency Conditions.
Response: The SDT agrees and has made the change. Footnote ‘b’ now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
American Electric Power	Yes	

Organization	Yes or No	Question 1 Comment
Exelon Transmission Strategy & Compliance	Yes	
Florida Municipal Power Agency	Yes	
IESO	Yes	
Northeast Utilities	Yes	
Pepco Holdings, Inc.	Yes	
US Bureau of Reclamation	Yes	
Manitoba Hydro	Yes	MH agrees with the SDT proposal.
Ameren	Yes	We were ok with the previous language. Though we do not intend to drop non-consequential load for a single contingency, we undersatnd that other ares may have been following such practice without degarding the relaibility of BES. We believe that they can continue this practice if they develop non-firm contracts with these customers.
Response: Thank you for your support. Several stakeholders proposed additional modifications and the drafting team did make several additional modifications to the footnote – please see the revised footnote.		

2. Are you aware of any conflicts caused by compliance with the proposed language in Table 1 — footnote b and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement? If yes, please identify the conflict.

Summary Consideration: The SDT understands that there may be conflicts as pointed out by respondents; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES. Strict numerical constraints applied across all of North America were not seen as appropriate. Instead, the SDT is leveraging existing processes to require documentation of Demand to be interrupted including alternatives evaluated and for the situation to be vetted in an open and transparent stakeholder process.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 2 Comment
Ameren	No	

Organization	Yes or No	Question 2 Comment
American Electric Power	No	
American Transmission Company	No	
BPA, Transmission Reliability Program	No	
Dairyland Power Cooperative	No	
Exelon Transmission Strategy & Compliance	No	
Independent Electricity System Operator	No	
Manitoba Hydro	No	
Midwest Reliability Organization	No	
Southern Company Transmission	No	
US Bureau of Reclamation	No	
South Carolina Electric & Gas	No	The comments expressed herein represent a consensus of the views of the above named members of the SERC Engineering Committee Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.
Response: Thank you for your response. Several stakeholders proposed additional modifications and the drafting team did make several additional modifications to the footnote – please see the revised footnote.		
Hydro-Québec TransEnergie (HQT)	Yes	Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict

Organization	Yes or No	Question 2 Comment
		between state and federal positions could place utilities in a compromising position.
Northeast Power Coordinating Council	Yes	Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.
IESO	Yes	It should be noted that conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. In RM-06-16-009, the Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." In the US, State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.Similar conflicts may also exist in Canada.
Progress Energy	Yes	There is the potential for conflict between Table 1 - Footnote (b) as currently proposed, which can be considered to regulate local distribution reliability without improving BES reliability, and local service reliability issues which are under the purview of state regulatory agencies. For example, the North Carolina Utilities Commission (NCUC) commented regarding this concern in the ballot which ended March 1 in Project 2006-02. Specifically, NCUC commented that they were "...concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1 is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions..." Progress Energy believes that NCUC's concerns are legitimate. BES reliability should address the avoidance and mitigation of cascading outages and BES facility damage, rather than limited, controlled local area loss of load, in order to avoid this conflict and overlap of regulation.
Response: The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES. Strict numerical constraints applied across all of North America were not seen as appropriate. Instead, the SDT is leveraging existing processes to require documentation of Demand to be interrupted including alternatives evaluated and for the situation to be vetted in an open and transparent stakeholder process.		

Organization	Yes or No	Question 2 Comment
Northeast Utilities	Yes	Northeast Utilities (NU) believes the language of the proposed revision to footnote 'b' can be better defined as the proposed revision is subject to interpretation by the different entities and regulatory agencies. Future conflicts can be minimized by further clarifying the proposed revision. Also, NU is concerned that this new modification does not specify the amount of permissible load shed nor does it require the planning entity to minimize load shedding under this exception.
Response: The SDT has made several clarifying changes to the footnote which should alleviate your concerns. Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Duke Energy	Yes	See response to question #1.
Georgia Transmission Corporation (Bulk System Planning)	Yes	See response to Question #1.

Organization	Yes or No	Question 2 Comment
Response: See response to question #1.		
Florida Municipal Power Agency	Yes	This is an area of fuzziness between State jurisdiction and Federal jurisdiction. In all honesty, shedding load for local area impacts has nothing to do with BES reliability and should not be under FERC jurisdiction under Section 215 of the Federal Power Act, but rather State jurisdiction for quality of service issues. However, there is also the matter of FERC jurisdiction over commercial matters and the opportunity to “game” the original footnote by transmission providers by allowing firm load shedding to grant firm transmission service for themselves, thereby avoiding or deferring transmission investment, while at the same time denying or requiring others to build the same transmission avoided in order to obtain transmission service. We can see how difficult it is from a drafting team’s perspective in achieving a balanced position between these different matters. The drafting team should be applauded for finding a reasonable position.
Pepco Holdings, Inc.	Yes	This is not an issue for historic PJM members, but as PJM has expanded and as a result of the merger of historic councils into RFC, I am aware that not all regions had standards equal to those of MAAC, and this has been an issue worked out between transmission planners (historic transmission owners) and their local regulators. It is ultimately a cost issue for loss of local load that does not affect the overall reliability of the interconnected BES.
Response: Thank you for your support.		
Tri-State Generation and Transmission Association, Inc.	Yes	We believe that FERC’s directive in FERC Order RM-06-16-009 to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for “reliable operation” of the bulk-power system to prevent “instability, uncontrolled separation or cascading failures,” none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission’s directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission’s reach beyond its review of measures that are needed for “reliable operation” of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission’s jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load.
Response: The SDT is not in a position to comment on FERC’s authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES. Such constraints would be determined through the open and transparent stakeholder process.		

3. Consideration of Comments on Initial Ballot — TPL Table 1 Order (Project 2010-11) May 17–27, 2010

Summary Consideration: The SDT has listened to the comments from the industry, understands the concerns raised, and has made changes to the footnote to balance the various industry concerns while assuring BES reliability.

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT from the cited inputs that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when load could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could

you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in this 2nd posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that likely will be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote 'b' to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~

o Interruptible Demand or Demand-Side Management

o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Rodney Phillips	Allegheny Power	1	Negative	Allegheny Power believes the loss of non-consequential load and/or curtailment of transmission service for N-1 contingencies should be limited to only extreme circumstances. Exception 2 of footnote b allows for the loss of non-consequential load for N-1 contingencies with no restriction. Allegheny Power recommends removing exception 2 footnote b.
Response: The SDT and the majority of the commenters disagree with this suggestion.				
Gordon Rawlings	BC Transmission Corporation	1	Negative	BCTC appreciates the good work of the SAR committee in drafting the changes to Footnote b of Table 1. BCTC agrees with the drafting team that interruption of firm load, served by either radial circuits or circuits that have became radial as a result of the contingency, should be allowed for N-1 contingencies. However, it is our position that interruption of firm load should not be limited only to such consequential loads. In our view, interruption of electric supply to some local network customers in the affected area should be permissible. This inclusion will allow transmission planners to plan BCTC's regional transmission network reliably and without impacting neighbouring transmission networks.
Faramarz Amjadi	BC Transmission Corporation	2	Negative	
Hubert C. Young	South Carolina Electric & Gas Co.	3	Negative	SCE&G has significant concern with the proposed revision to TPL Table 1, Footnote B. The current Footnote B states "Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted

Voter	Entity	Segment	Vote	Comment
				element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems”. The phrase “without impacting the overall reliability of the interconnected transmission systems” is important to the TPL standards to ensure that ERO standards do not dictate the level of service to customers. Service to customers and load pockets is jurisdictional to State Commissions and ERO standards should not compromise this jurisdiction. SCE&G believes that any proposed revisions to Footnote B must retain the concept that planned or controlled interruption of electric supply to customers, whether they are radial or network, is allowed as long as it does not impact the overall reliability of the interconnected transmission systems. The proposed revision eliminates this concept. There seems to be a general inconsistency and maybe confusion between the terms “reliability” and “level of service”.
David Frank Ronk	Consumers Energy	4	Negative	The current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the previous version of TPL-001-1. However, it still does not allow Transmission Planners to use appropriate and necessary discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should control the decision making when BES reliability is not an issue. Often, the consequences of these events are solely local in nature, requiring only minor additional loss of local load to avoid the costly major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load.
James B Lewis	Consumers Energy	5	Negative	
Hugh A. Owen	Public Utility District No. 1 of Chelan County	6	Negative	The interruption of a small amount of load is, under most conditions, not a risk to the reliability of the BES and is at times necessary to preserve reliability. The planned interruption of some load may be a cost effective alternative to a costly transmission project. That is a quality of service issue.
Michael Gammon	Kansas City Power & Light Co.	1	Negative	While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit
Charles Locke	Kansas City Power & Light Co.	3	Negative	
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	

Voter	Entity	Segment	Vote	Comment
				point of view to allow loss of non-consequential load.
Linda Brown	San Diego Gas & Electric	1	Affirmative	As to item (1), all load served directly by a transmission element which experiences a fault will be interrupted when the faulted element is taken out of service. This is the natural relationship between the load and the transmission element. Allowing this for BES elements may encourage transmission owners to remove transmission instead of upgrading or replacing it. Consider a load supplied by two transmission lines of different capacity. If the larger line is lost due to a contingency (N-1) and the remaining smaller line overloads the transmission owner is left with several options to address the problem: (1) move load between buses, (2) upgrade the smaller line, (3) add another line, or (4) create a radial load by removing the smaller line. Number (4) may be the least expensive and allowable under TPL-002, footnote b. Item (2) may also encourage transmission owners to develop plans which make load shedding part of category B. Consider a load served by three transmission lines, a utility may decide to remove a line, instead of upgrading, in order to set up a situation where an N-1 contingency would make the bus temporarily radial. In the event of a single outage (N-1), the load bus will be temporarily radial and load can be shed at the bus.
W. R. Schoneck	Florida Power & Light Co.	3	Affirmative	I believe the language is an improvement and clarifies the intent but I believe there still should be additional language added to give an exemption in meeting this requirement if it does not make economic sense(not economically feasible) and has no real impact on the BES.
Richard J Kafka	Potomac Electric Power Co.	1	Affirmative	It is understood that this is a compliance filing issue. This is not an issue for historic PJM members, but as PJM has expanded and as a result of the merger of historic councils into RFC, I am aware that not all regions had standards equal to those of MAAC, and this has been an issue worked out between transmission planners (historic transmission owners) and their local regulators. It is ultimately a cost issue for loss of local load that does not affect the overall reliability of the interconnected BES.
Alan Gale	City of Tallahassee	5	Affirmative	TAL thanks for SDT for the tireless effort to get to this point. TAL is voting affirmative with the following comments. We accept that the loss of non-consequential load is not a desired result for N-1 contingencies. It is also not the norm in system planning or operations. The flexibility to operate the system consistent with “good utility practice” may warrant the “odd-ball” case that would require this to occur. The dropping of non-consequential load

Voter	Entity	Segment	Vote	Comment
				will NOT lead to BES instability, voltage collapse, or cascading outages, which is what FERC and NERC are charged with preventing. It will lead to the shedding of load in a local area only. Utilities do not drop customers lightly. If the meter isn't turning, we are not getting paid, so we want the meter spinning. Utility power, while vital to our normal day-to-day lives and infrastructure, was never intended to be without interruption.
Brad Chase	Orlando Utilities Commission	1	Affirmative	This change raises the bar on transmission system performance. This change applies a blanket requirement upon entities that does not take into account the number of outages, probability of outages or cost to the customer. There are certain to be situations where this blanket requirement will result in increased cost to customers for no noticeable increase in reliability. OUC does agree with the concept of greater clarification on this requirement, however this clarification may raise the bar to far by trying to establish a blanket requirement. Duke, Progress Energy and others will be submitting comments with proposed language that attempt to address some of these issues and we encourage the drafting team to consider those comments.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of

Voter	Entity	Segment	Vote	Comment
				resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Eric Egge	Black Hills Corp	1	Negative	Black Hills believes that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Chifong L. Thomas	Pacific Gas and Electric Company	1	Negative	PG&E commends the SDT for developing the proposed footnote b. While it is a great improvement over the complete prohibition on loss of non-consequential load for any single contingency, the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system, especially where the impact is local in nature, to avoid instability, cascading or uncontrolled separation. Such planned interruption of load may be a reasonable alternative to the environmental impacts or prohibitive costs associated with a major new transmission project. Given the potential impacts of the proposed modification, further vetting of the issues is needed. PG&E believes that NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.

Voter	Entity	Segment	Vote	Comment
Thomas J. Bradish	RRI Energy	5	Negative	RRI supports the WECC position on this issue; namely, that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Trent Carlson	RRI Energy	6	Negative	
John Tolo	Tucson Electric Power Co.	1	Negative	The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project.
James Tucker	Deseret Power	1	Negative	The prohibition of loss of non-consequential load for events resulting the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including

Voter	Entity	Segment	Vote	Comment
				customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Louise McCarren	Western Electricity Coordinating Council	10	Negative	The proposed revisions to footnote b of Table 1 are an improvement to the recently balloted prohibition on loss of non-consequential load for single contingencies. The recognition of the new term "temporarily radial" is a step in the right direction. However, the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
William Mitchell Chamberlain	California Energy Commission	9	Negative	While the proposed revisions to footnote b are an improvement to the prohibition on loss of non-consequential load for a single contingency proposed in the recently failed TPL-001-1 ballot, the prohibition of loss of non-consequential load for events resulting the loss of a single element still inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is

Voter	Entity	Segment	Vote	Comment
				local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
John Mick	Colorado Springs Utilities	6	Negative	Colorado Springs Utilities ballot on the proposed changes to TPL Table 1, footnote b directed in FERC Order RM06-16-009 Colorado Springs Utilities wishes to vote NO on the proposed changes to TPL Table 1, footnote b, directed in FERC Order RM06-16-009. CSU concurs with the WECC position paper for the ballot, and agrees with the WECC statement "that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues".

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

The SDT agreed that a technical conference on this issue would be of value and held such a conference on August 10, 2010.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and

Voter	Entity	Segment	Vote	Comment
				~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Horace Stephen Williamson	Southern Company Services, Inc.	1	Negative	Comments have already been submitted previously, but it will be added here again. Proposed footnote should read... No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers when coupled with the appropriate re-dispatch of resources obligated to re-dispatch. It must be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. The proposed changes are based on the following... "The proposed wording by the drafting team seems to imply that the curtailment of firm transmission service is permitted to address single contingency constraints if coupled with the redispatch of network resources. The original language stated only that curtailments were permitted to prepare for the next contingency, not to address loading related to the initial contingency. The proposed wording could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint. Southern Companies recommend that the original language relating to "preparing for the next contingency" be incorporated into the drafting team's proposal."
Richard J. Mandes	Alabama Power Company	3	Negative	
Anthony L Wilson	Georgia Power Company	3	Negative	
Gwen S Frazier	Gulf Power Company	3	Negative	
Don Horsley	Mississippi Power	3	Negative	
Michael Ibold	Xcel Energy, Inc.	3	Negative	The proposed modification to footnote b of Table I in TPL-001 - 004 standards states that after a Category B contingency, there should not be any thermal, voltage or stability violation, no interruption of firm load (except the load that is directly connected to the elements that are removed from service as a result of the contingency) and no firm transfer curtailment (except when coupled with re-dispatch of resources obligated to re-dispatch). We believe the proposed footnote b creates a gap between TPL-002 and TPL-003 standards, since it does not address conditions when firm load shedding and firm transfer curtailments are not required to meet the system performance for Category B contingency, but one or both are the required system adjustments to prepare for the next contingency (Category C3). When firm transfer is curtailed after the first contingency in
Liam Noailles	Xcel Energy, Inc.	5	Negative	
David F. Lemmons	Xcel Energy, Inc.	6	Negative	

Voter	Entity	Segment	Vote	Comment
				preparation for the next contingency, it is not clear from the proposed footnote b if this is considered a valid system adjustment for Category C or a violation of Category B. Recall that the existing footnote b addresses this condition explicitly by stating “To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm Transfers.”
George T. Ballew	Tennessee Valley Authority	5	Affirmative	TVA appreciates the work of the SDT on this issue. However, TVA recommends revising the second paragraph of the revised footnote b: “To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. However, curtailment of Firm Transmission Service is only allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions should also be respected.” Without the changes in the first two sentences above, the proposed wording by the SDT could be interpreted to allow re-dispatch/firm curtailments to address any single contingency constraint instead of in preparation for the next contingency.
Marjorie S. Parsons	Tennessee Valley Authority	6	Affirmative	
Larry Akens	Tennessee Valley Authority	1	Affirmative	TVA appreciates the work of the SDT. However, TVA recommends revising the second paragraph of the revised footnote "b". Without changes in the first two sentences, the proposed wording by the SDT could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint instead of in preparation for the next contingency.

Response: The SDT believes that System re-dispatch is an acceptable System adjustment to “remain within applicable Facility Ratings” to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote ‘b’ clarifies that re-dispatch is allowable to “remain within” ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words “To prepare for the next Contingency” to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

Footnote ‘b’ now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand.

Voter	Entity	Segment	Vote	Comment
				Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Robert W. Roddy	Dairyland Power Coop.	1	Negative	DPC CONCURS WITH THE MRO COMMENTS.
Jason Shaver	American Transmission Company, LLC	1	Affirmative	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed if the tripping of the load is either accepted or volunteered by the customer.
Lawrence R. Larson	Otter Tail Power Company	1	Negative	The change precludes the use of direct load control systems that should be allowed to relieve transmission problems. These systems control firm transmission load but rate conditions can allow their use to mitigate transmission problems.
Response: *(Note - MRO did not submit comments with the initial ballot – but did submit the following comment during the formal comment period: For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.)*				

Voter	Entity	Segment	Vote	Comment
The SDT has modified the footnote to address your concern. Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
Ajay Garg	Hydro One Networks, Inc.	1	Negative	Hydro One is casting a negative vote for the following reasons: 1. The amendment to the footnote does not add any technical value to the standard. It was added only to satisfy a FERC directive to address comments made to allow non-consequential load loss after a single contingency event, "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." 2. Addressing curtailment of Firm Transmission Service with re-dispatch of resources is a matter of a commercial nature and should be dealt with in the agreements dealing with such services. Issues of contracted transmission services, firm or otherwise, are not a reliability related matter and are not to be dealt with in this standard.
Michael D. Penstone	Hydro One Networks, Inc.	3	Negative	

Voter	Entity	Segment	Vote	Comment
				3. Matters of interruption of firm load should be incorporated into this standard only after the FERC NOPR on the definition of the BES is resolved. As it stands, the footnote will pose significant problems if the 100 kV and above FERC proposal is applied across the board, unless the standard specifically states that it applies to the BES as defined by the region (current definition).

Response: 1. & 2. The SDT disagrees. The SDT believes that there could be a direct impact on reliability of the BES associated with uncontrolled interruption of Demand and that it is important to discourage and limit the use of this option.The SDT has added clarity to the footnote.

Footnote ‘b’ now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

3. The SDT disagrees that this needs to wait on the FERC NOPR. This standard is applicable to the BES as it is defined.

Voter	Entity	Segment	Vote	Comment
Spencer Tacke	Modesto Irrigation District	4	Negative	I am voting NO vote because of the lack of clarity of the second paragraph of the proposed change. Although paragraph 1 is an improvement to the current wording, and actually allows for some specific flexibility in shedding load for an N-1 event, the lack of clarity in the second paragraph could lead to varied interpretations by members and compliance

Voter	Entity	Segment	Vote	Comment
				auditors. Thank you.

Response: The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Dana Cabbell	Southern California Edison Co.	1	Negative	It is SCE's position that the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local
David Schiada	Southern California Edison Co.	3	Negative	

Voter	Entity	Segment	Vote	Comment
Ahmad Sanati	South California Edison Company	5	Negative	regulator input, for their individual system. When planned load interruption is identified as a response to a single event, the impact to the system is often local in nature. The planned interruption of load may be a desirable alternative to the prohibitive costs associated with a major new transmission project. If the NERC Standards Drafting Team decides to proceed with footnote B, as written, it needs to ensure that Transmission Owners, Transmission Operators, and Transmission Planners have enough time to both design and implement any mitigation plans necessary to be compliant with the new language. In almost all cases the actual implementation of a solution requiring new construction will be dependent on a number of different regulatory agencies providing the necessary permits allowing for its construction. As such, NERC needs to ensure that any time frame associated with compliance to the proposed language be variable, and allow for extended implementation time frames based on system conditions that may delay placing mitigation plans in service. An example of a reasonable variable time frame to be compliant with the proposed language in footnote B would be to start the clock 60 months from receiving the pertinent environmental permitting. In California this could be the issuance of a Draft Environmental Impact Review pursuant to the California Environmental Quality Act.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

The SDT has added more latitude for the Transmission Planner with the modifications and believes that 60 months should be sufficient.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the~~

Voter	Entity	Segment	Vote	Comment
				~~Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Henry Ernst-Jr	Duke Energy Carolina	3	Negative	On the initial ballot of TPL-001-1 Duke Energy also voted "Negative", primarily because Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We also sought rehearing on the Commission's March 18 Order Setting Deadline for Compliance (Docket No. RM06-16), with respect to this and other issues. We believe that FERC's directive in that Order to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the potential impacts (environmental, historical, archaeological, aesthetic...) of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. With this "Negative" vote, Duke

Voter	Entity	Segment	Vote	Comment
				offers the following ideas on alternatives for the SDT to consider that will allow for appropriate discretion and facilitate proper planning while allowing non-consequential load loss (NCLL). The standard should allow for dropping of limited amounts of non-consequential load in situations where it would be reasonable for a bounded time period and under restricted system conditions (e.g. 1-3 years only when load is >90 % of peak conditions). Dropping of non-consequential load would be prudent planning in situations where the near term impact of load projections or implementation of nearby transmission/generation projects will alleviate the necessity of an upgrade to meet N-1 conditions. Also, reliability of service to end-use customer is impacted by the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customers' level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to avoid projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics (e.g. SAIFI/SAIDI/ASAI) should also be considered by the SDT for determination of acceptable use of NCLL.
Luther E. Fair	Gainesville Regional Utilities	1	Affirmative	Even though I am voting in the affirmative, I agree that most of the comments offered by Duke and Norther Indiana in their earlier statements have merit and should be considered. Also, I believe that the use of reliability metrics should be considered by the SDT for determination of acceptable use of NCLL.
Mace Hunter	Lakeland Electric	3	Negative	Reliability should consider the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customer's level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to delay projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics should also be considered by the SDT for determination of acceptable use of NCLL.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.				

Voter	Entity	Segment	Vote	Comment
				Footnote ‘b’ now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Sammy Roberts	Progress Energy Carolinas	1	Negative	Progress Energy applauds NERC’s efforts to improve the footnote (b) language with respect to conditional allowance of curtailing Firm Transmission Service, which is addressed in the second paragraph of the proposed new footnote (b). PE remains concerned, however, that the first paragraph of the proposed new footnote (b) does not allow for curtailment of non-radial non-consequential load. The ability to curtail non-consequential load in the planning horizon can be a useful tool to mitigate local area issues, and has not been detrimental to
Lee Schuster	Florida Power Corporation	3	Negative	

Voter	Entity	Segment	Vote	Comment
Sam Waters	Progress Energy Carolinas	3	Negative	the Bulk Electric System (BES). Disallowing the curtailment of non-radial non-consequential load essentially prohibits taking action in situations in which the load in question is clearly at a localized self-contained level of the system, i.e. the distribution system(s) served by the Transmission Owner. Prohibiting the curtailment of local load thus constitutes regulating distribution feeder reliability rather than BES reliability. Events that could be mitigated through the curtailment of local, non-radial non-consequential load are infrequent, and such curtailment has no material effect on the reliability of the BES. PE therefore suggests that the following addition (item (3)) to the first paragraph of the proposed footnote (b) be considered: "No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, and/or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities, and/or (3) Planned or controlled interruption of any additional Load required to mitigate the post-contingency results, provided that the non-consequential load being shed for the event is localized, and provided that the total load shed for the event does not exceed 2% of the Planned system peak demand or 200 MW, whichever value is less."
Wayne Lewis	Progress Energy Carolinas	5	Negative	

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The SDT did not adopt a numerical limit as it believes that any single numerical value applied on a ntion-wide basis was not equitable for all entities.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial~~

Voter	Entity	Segment	Vote	Comment
				~~Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Timothy VanBlaricom	California ISO	2	Negative	The California ISO supports NERC's request for a public technical conference to be held, as described in NERC's April 19, 2010 request for rehearing and motion for stay of the March 18 Order (RM06-16-009), to provide the opportunity to gain industry input and written comments regarding the Commission's TPL-002-0 directive for NERC to develop a modification to the TPL-002-0 Table 1 footnote b.
Response: The SDT agreed that a technical conference would be of value and held such a conference on August 10, 2010.				
Terry L. Blackwell	Santee Cooper	1	Negative	The Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning processes appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. Table B footnote still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, and local customers should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. The Commission's directive sets forth an expectation that NERC is to implement standards that address all loss of load at costs that may not be commensurate with bulk power system reliability, as statutorily defined, which is fundamentally different from what the Reliability Standards were intended to do.
Zack Dusenbury	Santee Cooper	3	Negative	
Suzanne Ritter	Santee Cooper	6	Negative	

Voter	Entity	Segment	Vote	Comment
Response: The SDT is not in position to comment on FERC's authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.				
Kimberly J. Jones	North Carolina Utilities Commission	9	Negative	The NC Utilities Commission is concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1, and as explained in draft footnote b, is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions. This requirement does not provide any benefit to reliability of the bulk electric system and could undermine state efforts to balance reliability issues with cost of service issues. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load, understanding that state commissions are positioned to force electric utilities to address local service quality issues on an expedited basis, should it be necessary and in the public interest.
Response: The SDT understands the concern but believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES. The SDT's approach will leverage existing processes to document and vet the situation. Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the				

Voter	Entity	Segment	Vote	Comment
Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Negative	THE PROPOSED INTERPRETATION WILL UNDERMINE THE INTERNATIONAL STANDARDS SETTING PROCESS AND COULD RESULT IN DIFFERING INTERPRETATIONS OF STANDARDS ON THE NORTH AMERICAN BULK-POWER SYSTEM.
Response: The SDT disagrees and believes that the footnote has been clarified appropriately within the standards development process.				
Daryn Barker	Louisville Gas and Electric Co.	6	Negative	The revised footnote b on Table 1 imposes additional requirements on the responsible entities. The footnote states: Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. However, R1 states: The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned These statements address different and inconsistent scope. If the change in scope was intended then a change should also be made to R1 to reconcile the inconsistency.
Charlie Martin	Louisville Gas and Electric Co.	5	Negative	Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. However, R1 states: The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned These statements address different and inconsistent scope. If the change in scope was intended then a change should also be made to R1 to reconcile the inconsistency.
Response: The SDT agrees that your assessment is for your portion of the interconnected grid. However, when performance in one system is dependent on generation dispatch in another system or vice versa, the SDT believes that one must ensure that the re-dispatch is feasible. The SDT does not believe that this presents a conflict with Requirement R1.				
John Apperson	PacifiCorp	3	Negative	This proposal warrants a "no" vote due to the current uncertainty regarding the outcome of the FERC TPL-002 NOPR issued by FERC on March 18, 2010. The impacts of the proposed changes to footnote B cannot be assessed separately from the alternative interpretation of TPL-002 proposed by FERC. The proper planning of a transmission system requires that all performance requirements are known and understood. If only some of the requirements are known and understood it is impossible to properly plan, study, assess, and operate the

Voter	Entity	Segment	Vote	Comment
				transmission system.
Response: The current TPL-002 is in force and will remain so until the completion of the cited FERC NOPR. This limited scope revision to footnote 'b' is to add clarity to what is in effect.				
Keith V. Carman	Tri-State G & T Association Inc.	1	Negative	Tri-State does believe that the new footnote is an improvement, but thinks there are still some changes necessary. We believe that the word "only" should be removed from the phrase "…where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities" because that discrimination was not required in FERC Order RM-06-16-009. There may be times when facilities near the temporary radial facilities might fall outside the limits set in reliability criteria but the situation is mitigated if the load shedding occurs at the radial facility. The meaning of the second paragraph of the new footnote is unclear. Tri-State recommends changing it to "Curtailment of Firm Transmission Service is not allowed unless it is coupled with curtailment-offsetting resources that are obligated to re-dispatch. Further, the curtailment activities cannot result in the shedding of any Firm load or in violations of Facility Ratings, either internal or external to the planning region." We believe that FERC's directive in FERC Order RM-06-16-009 to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.				

Voter	Entity	Segment	Vote	Comment
Footnote ‘b’ now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected. The SDT is not in position to comment on FERC’s authority.				
Claudiu Cadar	GDS Associates, Inc.	1	Negative	We do not agree with the proposed changes due to several reasons. Although the proposed change will directly influence the reliability standards and transmission system performances, will also have an indirect impact on the economic side with respect to the expansion of existing transmission system. We believe that FERC directive as stipulated in Order 693 cannot constrict, nor impose certain actions outside of the reliability limits. We believe that since these events are merely isolated and rarely enforced, the decision of mandating a great financial effort as a consequence of the proposed changes would certainly be counterbalanced by its feasibility when compare with the current cost of load shedding. While the revised footnote b can be certainly considered an improvement from the current version, however it still does not allow the joined entities involved to have power over the decision making when BES reliability is not an issue. We also believe that any mandatory changes implemented in the TPL standards under the

Voter	Entity	Segment	Vote	Comment
				current scenario are not entirely feasible unless all other issues such as the definition of the BES, Consequential / Non-consequential Load, BES Critical Element, etc gets resolve ahead. The revision with respect to load shedding, specifically the portion about shedding loads on newly radial facilities, does not match the version 1 TPL standard definition of consequential load loss. To approve the proposed revision to footnote 'b' would create an unnecessary discrepancy between the version 1 TPL standard under consideration and the existing standards. We recognize that the Version 1 will replace Version 0, but since it appears that the performance standard with respect to footnote 'b' is intended to be same in the revised footnote and the Version 1 standard, it only makes sense that the revised version 0 footnote 'b' match the consequential load loss definition contemplated in Version 1. In the light of the above we suggest the Commission to approach different other solutions and ideas for improving the current reliability of the transmission system without enforcing decisions beyond its statutory scope. We advance an alternative to this matter meant to balance the reliability of the transmission system and its indirect financial impact. Although the solution that we offer would require an extended time for development and implementation, however we urge NERC to consider it in its further approach. Our alternative consists mainly in implementing an additional term such as "Critical Load" which we have briefly figured that would consist in particular load necessary to be maintained in service without interruption. Even though this new term would seemed to be at first related with the quality of the service, however a joint association of transmission planners, customers, regulatory entities as decision makers can simply individualize the load that cannot be shed, as well as future transmission improvements that will be required to serve this envisioned small amount of load rather than the entire load. In this way we will create a reasonable balance in between the reliability of the transmission system and the cost to maintain / improve this reliability.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td colspan="5">interruption of Demand is utilized within the planning process, such interruption is limited to:

o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~

o Interruptible Demand or Demand-Side Management

o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

The current TPL-002 is in force and will remain so for the forseeable future. This limited scope revision to footnote 'b' is to add clarity to what is in effect.

Project 2006-02 is under revision and the clarifications of footnote 'b' will be considered by the SDT for future revisions of TPL-001-2.

The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.</td></tr>
<tr><td>Ronald D. Schellberg</td><td>Idaho Power Company</td><td>1</td><td>Negative</td><td>While the proposed revisions are an improvement to the prohibition on loss of non-consequential load for a single contingency proposed in the recently failed TPL-001-1 ballot, that the prohibition of loss of non-consequential load for events resulting the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues.

However, the removal of: "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." will require significant adjustments in either TRM or TTC reductions to be compliant with this revised standard in the WECC Region. To construct additional transmission facilities to maintain present day business could easily exceed 10 Billion dollars throughout the WECC region. For example, the Pacific AC Intertie currently has a TTC of 4800 MW spread across 3 500 kV transmission lines. With the loss of one Transmission line, the Pacific AC intertie drops to 3200 MW. Removal of this sentence</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
				would require TP either to drop the Firm TTC of the Intertie to 3200, or include a TRM reservation of at least 1600 MW. The TPs would not be able to say that a loss of 1600 MW of import capacity would not result in curtailments of firm load. Just about all multi transmission line paths in the WECC Region would suffer. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. In the case of long interties between subregions of WECC, these interties have never been planned to operate in this manner. Idaho Power recommends that the sentence permiting system adjustments be reinserted into Footnote B.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

The SDT believes that System re-dispatch is an acceptable System adjustment to “remain within applicable Facility Ratings” to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote ‘b’ clarifies that re-dispatch is allowable to “remain within” ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words “To prepare for the next Contingency” to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

Footnote ‘b’ now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the

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				Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Francis J. Halpin	Bonneville Power Administration	5	Affirmative	For consistency, regarding the firm transfer issue, the term "Firm Transmission Service" should be replaced with "Firm Transfers" in order to be consistent with the fourth column of the existing Table 1 "Transmission System Standards - Normal and Emergency Conditions".

Response: The SDT agrees and has made the change.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

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- o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application

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				is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Kim Warren	Independent Electricity System Operator	2	Affirmative	IESO supports the revisions made to footnote 'b' based on the present definitions of BES and Firm Demand and on the understanding that the NERC standards apply only to the BES as defined in the NERC Glossary as follows: "As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighbouring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." To be clear, our interpretation of the present definition of BES is that it defers to each Regional Reliability Organization to define the elements of the power system that are considered BES and, therefore in the NPCC Region, "BES as defined by NERC" = "BPS as defined by NPCC".
Response: The SDT agrees that the standard applies to the BES as defined in the Glossary.				
Jacquie Smith	ReliabilityFirst Corporation	10	Affirmative	If this revision is an urgent action, then the implementation timeframe should be shorter. In the clarification paragraph below, I do not understand the first sentence. Are there commas missing? What is the requirement and what is the exception? Also, I question the validity of using "should" in the second sentence. If it is a requirement, then it needs to be stated as a requirement. If it is a suggestion, then it does not belong in the standard. No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.
Response: This was originally classified as an 'urgent action' revision to meet the FERC due date which was June 30, 2010, not because NERC had classified the modification as urgent for reliability. Note that FERC modified the due date to March 31, 2011 - this allows several more months of				

Voter	Entity	Segment	Vote	Comment
development time and the SAR was revised to indicate that the proposed modification to footnote ‘b’ is no longer an Urgent Action revision. Commas have been added as appropriate and a re-wording was made which should make this clear. ‘Should’ has been replaced by ‘would’ to provide additional clarity. Footnote ‘b’ now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
David H. Boguslawski	Northeast Utilities	1	Affirmative	Northeast Utilities (NU) believes the language of the proposed revision to footnote ‘b’ can be better defined as the proposed revision is subject to interpretation by the different entities and regulatory agencies. Future conflicts can be minimized by further clarifying the proposed revision. Also, NU is concerned that this new modification does not specify the amount of permissible load shed nor does it require the planning entity to minimize load shedding under this exception.
Response: The SDT has made several clarifying changes to the footnote which should alleviate your concerns.				

Voter	Entity	Segment	Vote	Comment

. Footnote ‘b’ now reads:

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Donald S. Watkins	Bonneville Power Administration	1	Affirmative	On the firm transfer issues, the term "Firm Transmission Service" should be replaced with "Firm Transfers" to be consistent with the fourth column of the existing Table 1 Transmission System Standards - Normal and Emergency Conditions.
Rebecca Berdahl	Bonneville Power Administration	3	Affirmative	
Brenda S. Anderson	Bonneville Power Administration	6	Affirmative	

Response: The SDT agrees and has made this change.

Footnote ‘b’ now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand.

Voter	Entity	Segment	Vote	Comment
				Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Frank Gaffney	Florida Municipal Power Agency	4	Affirmative	Please see FMPA comments submitted through the concurrent comment period for Project 2010-11
David Schumann	Florida Municipal Power Agency	5	Affirmative	
Response: Please see the response to FMPA comments above.				
Carter B Edge	SERC Reliability Corporation	10	Affirmative	The footnote makes clearer when load can be dropped for planning purposes. By making this footnote more specific, it supports reliability and helps stakeholders apply the TPL standards.
Response: Thank you for your support.				

Voter	Entity	Segment	Vote	Comment
Timothy Beyrle	City of New Smyrna Beach Utilities Commission	4	Affirmative	This is an area of fuzziness between State jurisdiction and Federal jurisdiction. In all honesty, shedding load for local area impacts has nothing to do with BES reliability and should not be under FERC jurisdiction under Section 215 of the Federal Power Act, but rather State jurisdiction for quality of service issues. However, there is also the matter of FERC jurisdiction over commercial matters and the opportunity to "game" the original footnote by transmission providers by allowing firm load shedding to grant firm transmission service for themselves, thereby avoiding or deferring transmission investment, while at the same time denying or requiring others to build the same transmission avoided in order to obtain transmission service. We can see how difficult it is from a drafting team's perspective in achieving a balanced position between these different matters. The drafting team should be applauded for finding a reasonable position.
Response: Thank you for your support.				
Larry E Watt	Lakeland Electric	1	Affirmative	This issue is better handled within the development of the new TPL-001 standard.
Response: The current TPL-002 is in force and will remain so until the completion of the TPL-001-2 effort. This limited scope revision to footnote 'b' is to add clarity to what is in effect.				

Consideration of Comments on TPL Table 1 Order (footnote 'b') — Project 20010-11

The TPL Table 1 Order Drafting Team thanks all commenters who submitted comments on the revised footnote. These standards were posted for a 30-day informal public comment period from September 8, 2010 through October 8, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 42 sets of comments, including comments from more than 96 different people from approximately 75 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

Comments can be reviewed in their original format on the following project page:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Industry response was divided in relation to support for the proposed footnote 'b' which was posted for an informal comment period through October 8, 2010. Although there were a number of supporters for the proposed footnote they were outnumbered by the commenters who did not support the footnote text for various reasons and offered their views and concerns.

The Standard Drafting Team (SDT) carefully considered the feedback provided including minority opinions such as not allowing Demand interruption at all and has made clarifying revisions to the footnote 'b' text.

The revised footnote 'b' is:

b) An objective of the planning process ~~is to avoid~~ should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. ~~Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process~~. However, it is recognized that Demand ~~may need to~~ will be interrupted if it is directly served by the elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- ~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~
- Interruptible Demand or Demand-Side Management
- ~~Demand that does not adversely impact overall BES reliability where the c~~Circumstances ~~describing~~ where the use of ~~such~~ Demand interruption are documented, including alternatives evaluated; and where the ~~application~~ Demand interruption is subject to review ~~and acceptance~~ in an open and transparent stakeholder process that includes addressing stakeholder comments.

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Based on the review of comments received and the fact that only clarifying changes were made due to those comments, the SDT is recommending that this project be moved forward to balloting.

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

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

Index to Questions, Comments, and Responses

The Industry Segments are:

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council	10									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Micahel Schiavone	National Grid	NPCC	1
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Dean Ellis	Dynegy Generation	NPCC	5
8.	Brian Evans-Mongeon	Utility Services	NPCC	8
9.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	Chantel Haswell	FPL Group, Inc.	NPCC	5
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Michael R. Lombardi	Northeast Utilities	NPCC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	Saurabh Saksena	National Grid	NPCC	1

2.	Group	Philip R. Kleckley	SERC Planning Standards Subcommittee	1, 3, 5

Additional Member	Additional Organization	Region	Segment Selection	
1.	Bob Jones	Southern Company Services - Trans	SERC	1
2.	John Sullivan	Ameren	SERC	1
3.	Charles Long	Entergy	SERC	1
4.	Jim Kelley	PowerSouth Energy Cooperative	SERC	1
5.	Pat Huntley	SERC Reliability Corporation		10

3.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	WPS Corporation	MRO	3, 4, 5, 6
4.	Jason Marshall	Midwest ISO Inc.	MRO	2
5.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
6.	Ken Goldsmith	Alliant Energy	MRO	4
7.	Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6
8.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
9.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
10.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
11.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
12.	Scott Nickels	Rochester Public Utilties	MRO	4
13.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6

#	Group/Individual	Commenter	Organization	Registered Ballot Body Segment
4.	Group	Denise Koehn	Bonneville Power Administration	1, 3, 5, 6

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chuck Matthews	BPA, Transmission Planning	WECC	1
2.	Berhanu Tesema	BPA, Transmission Planning	WECC	1
3.	Kyle Kohne	BPA, Transmission Planning	WECC	1
4.	Kendall Rydell	BPA, Transmission Planning	WECC	1
5.	Rebecca Berdahl	BPA, Long Term Sales and Purchases	WECC	3

#	Group/Individual	Commenter	Organization	Registered Ballot Body Segment
5.	Group	Louis Slade, Jr.	Dominion	1, 3, 5, 6

	Additional Member	Additional Organization	Region	Segment Selection
1.	Angela Park	Electric Transmission	SERC	1, 3
2.	John Loftis	Electric Transmission	SERC	1, 3
3.	Mike Garton	Electric Market Policy	NPCC	5, 6
4.	Michael Gildea	Electric Market Policy	RFC	5, 6

#	Group/Individual	Commenter	Organization	Registered Ballot Body Segment
6.	Group	Ben Li	IRC Standards Review Committee	2

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Phillips	MISO	MRO	2
2.	Partick Brown	PJM	RFC	2
3.	James Castle	NYISO	NPCC	2
4.	Mark Thompson	AESO	WECC	2
5.	Charles Yeung	SPP	SPP	2
6.	Greg Van Pelt	CAISO	WECC	2
7.	Matt Goldberg	ISO-NE	NPCC	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Individual	Jana Van Ness	Arizona Public Service Company	X		X		X					
8.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
9.	Individual	John Cummings	PPL Corp	X		X		X					
10.	Individual	Andy Tillery	Southern Company	X		X							
11.	Individual	Don Gilbert	JEA	X		X		X					
12.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
13.	Individual	Laura Zotter	ERCOT ISO		X								
14.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
15.	Individual	Steve Stafford	Georgia Transmission Corporation	X									
16.	Individual	John Canavan	NorthWestern Energy	X									
17.	Individual	Tim Ponseti	TVA Transmission Planning & Compliance	X		X		X				X	
18.	Individual	Gordon Rawlings	BC Hydro	X	X	X		X					
19.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
20.	Individual	John Sullivan	Ameren	X		X		X	X				
21.	Individual	Darcy O'Connell	California ISO		X								
22.	Individual	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
23.	Individual	Orlando A Ciniglio	Idaho Power	X		X		X					
24.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
25.	Individual	Thad Ness	American Electric Power	X		X		X	X				
26.	Individual	JC Culberson	ERCOT		X								
27.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
28.	Individual	Charles Lawrence	American Transmission Company	X									
29.	Individual	Kathleen Goodman	ISO New England Inc.		X								
30.	Individual	Dan Rochester	Independent Electricity System Operator		X								
31.	Individual	Ed Davis	Entergy Services	X		X		X	X				
32.	Individual	Terry Harbour	MidAmerican Energy	X		X		X	X				
33.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				
34.	Individual	Jonathan Appelbaum	United Illuminating Co	X									
35.	Individual	Michael Moltane	ITC	X									
36.	Individual	Gregory Campoli	New York Independent System Operator		X								
37.	Individual	David Kiguel	Hydro One Networks Inc.	X		X							
38.	Individual	Jason Marshall	Midwest ISO		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
39.	Individual	Claudiu Cadar	GDS Associates Inc.	X									
40.	Individual	Chifong Thomas	Pacific Gas and Electric Co.	X		X		X					
41.	Individual	Catherine Koch	Puget Sound Energy	X									
42.	Individual	Harold Wyble	Kansas City Power & Light	X		X		X	X				

1. The SDT is proposing a revision to footnote 'b' in the TPL tables to comply with FERC Orders which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.

Summary Consideration: Industry response was divided in relation to support for the proposed footnote 'b' which was posted for an informal comment period through October 8, 2010. Although there were a number of supporters for the proposed footnote they were outnumbered by the commenters who did not support the footnote text and offered their views and concerns.

The Standard Drafting Team (SDT) carefully considered the feedback provided and has made clarifying revisions to the footnote 'b' text. For each major item, the SDT has addressed the issue raised and has summarized any revision made to footnote 'b' in response to the feedback provided. The SDT appreciates industry input and believes the changes made are responsive to the comments received.

Open and Transparent Process: Most of the comments received related to the use of an "open and transparent" stakeholder process as described in the proposed footnote 'b'. While the comments on this topic varied, the majority of comments indicated that such a process should not be included within a mandatory Reliability Standard and cited that FERC Order 890 already requires the sharing of planning information. Others indicated that the statement for "review and acceptance" exceeds expectations required by FERC Order 890 and that an entity's compliance to a Reliability Standard should not be subject to the "acceptance" of stakeholders and that a process conforming with FERC Order 890 principles already requires dispute resolution. Some commenters expressed support of the process and it is noted that those who responded "Yes" with no comment were assumed to support the process "as is".

The SDT's inclusion of a stakeholder review in footnote 'b' was driven by the fact that FERC Order 890 does not fully cover the continent-wide footprint addressed by a NERC Reliability Standard. Additionally, footnote 'b' is being applied to address localized Bulk Electric System performance and not a wide-area Bulk Electric System concern that is generally the focus of the "open and transparent" process governed by FERC Order 890.

The SDT thoroughly considered all comments on the stakeholder process model. The SDT continues to support a Reliability Standard providing mandatory enforcement utilizing a stakeholder process where any intended use of planned Demand interruption has transparency and that stakeholders have the opportunity to comment on its use. However, upon further reflection the majority of SDT members agreed that including the "acceptance" aspect of the stakeholder process presents challenges within the context of a Reliability Standard and "acceptance" has been removed. The SDT agrees with opinions that an entity's compliance should not be subject to the "acceptance" of its plans by stakeholders. Also, the SDT realizes that for most entities there is a final, high level review with acceptance or approval of Transmission plans at the local level. So, while the footnote no longer references the need for stakeholder acceptance, the expectation is that there will be a review process in place that will consider the implementation of any plan calling for Demand interruption as explained in the footnote.

In addition, the SDT has revised footnote 'b' to explicitly require a response to any challenges presented via the stakeholder process.

Demand vs. Load: Several commenters questioned the SDT's use of the term "Demand" instead of "Load" in the proposed footnote. The SDT clarifies that this was intentional as the existing, approved TPL suite of standards uses the term Demand throughout the requirement text. Additionally, the existing, approved TPL performance requirements documented in Table I contain the column heading "Loss of Demand or Curtailed Firm Transfers" which is the subject of the footnote 'b' applicability for category B (single element) Contingencies. This project, Project 2010-11, aims to address footnote 'b' regulatory directives with no change to the remainder of the standard. Therefore, for consistency with the existing standard text, the term Demand is retained.

Firm transfer vs. Firm Transmission Service: Some stakeholders suggested that the SDT revert back to the use of "Firm Transmission Service" instead of the undefined term "firm transfers." The SDT clarifies that that the change to "firm transfers" was intentional as the existing, approved TPL suite of standards references "firm transfers" both in requirement text and Table I. The existing, approved TPL performance requirements documented in Table I contain the column heading "Loss of Demand or Curtailed Firm Transfers" which is the subject of the footnote 'b' applicability for category B (single element) Contingencies. This project, Project 2010-11, aims to address footnote 'b' regulatory directives with no change to the remainder of the standard. Therefore for consistency with the existing standard text, the term 'firm transfer' is retained.

Amount of Demand Loss: The majority of commenters agree with the SDT's clarifications regarding interruption of Demand as defined in the proposed footnote 'b'. The majority of entities who commented support the limited use of Demand interruption and that when used to address a BES performance requirement agree that it should be documented, and made known through a stakeholder process. However, as stated above, the majority stopped short of supporting a mandatory Reliability Standard requiring "acceptance" by other entities for the planned interruption of Demand.

Other minority views propose to limit or cap the amount of Demand loss and some suggested 50 MW as the appropriate level. Some felt the SDT's prior approach of limiting the Demand loss to only "radial" line configurations was appropriate and superior to the "open process" approach. It is also noted that some commenters went further to say no loss of Demand should be allowed for a single Contingency, but this was clearly a minority view of the comments submitted.

The SDT carefully considered the comments and unanimously agreed that defining a Demand level limit is problematic based on the vast differences in BES applications across the continent and that each potential use is case specific. The SDT also had concerns that setting such a limit may have the unintended consequences of planned Demand interruption being more widely accepted in practice in Transmission planning. The SDT and most commenters are of the opinion that a stakeholder review process is a better deterrent for Demand interruption and will appropriately guard against any misuse.

The revised footnote 'b' is:

b) An objective of the planning process ~~is to avoid~~ should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. ~~Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process~~. However, it is recognized that Demand ~~may need to~~ will be interrupted if it is directly served by the elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- ~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~
- Interruptible Demand or Demand-Side Management
- ~~Demand that does not adversely impact overall BES reliability where the c~~Circumstances ~~describing~~ where the use of ~~such~~ Demand interruption are documented, including alternatives evaluated; and where the ~~application~~ Demand interruption is subject to review ~~and acceptance~~ in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	1. The introductory paragraph discourages the Interruption of any Demand, implying that no Demand directly connected should be interrupted. However, it is an acceptable practice to allow for some Interruption of Demand that is directly connected to the element that is removed from service. Recommend that the drafting team revise the wording to eliminate this implication, and soften the expectation such that it is recognized that some Interruption of Demand is unavoidable by system configuration, but that each entity should establish a reasonable limit on how much demand can be interrupted due to the loss of an element. 2. The Statement that “However, Demand may need to be interrupted in limited circumstances to address BES performance requirements” in the introductory paragraph contradicts bullet 3 “Demand that does not adversely affect BES ...” 3. The third Bullet is confusing. Suggest revising the wording to clarify the adverse impact to the BES system, documentation expectations, and to answer fundamental questions such as who has the authority to decide the use if the stakeholder process is “accepting”, and the necessity of having a stakeholder process. It is unlikely that the interruption of Demand will adversely impact the BES system. This constraint is too broad. The language in this bullet also allows that non-consequential Demand interruption could be used to mitigate reliability violations arising from the NERC Category B contingency events (i.e., single element contingencies). 4. In the second paragraph, the conditions when interruption of Firm Transfers may be used are not specified. 5. In the last sentence of the second paragraph, “would” should be replaced by “must”. Alternatively, possible rewording of footnote “b” to be considered: b) An objective of the planning process should be to minimize the likelihood of interrupting Demand and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements or other local reasons which have no adverse impact on overall BES reliability or the interconnected BES. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Demand that does not adversely impact overall reliability of the BES or the interconnected BES and where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of available resources, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected. The Drafting Team should reconsider the use of “Load” as opposed to “Demand”. By definition (NERC

Organization	Yes or No	Question 1 Comment
		Glossary dated April 20, 2010) Demand is:"1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer."Load is defined as:"An end-use device or customer that receives power from the electric system."This terminology is more appropriate to the application used in the Table.
Hydro One Networks Inc.	No	1. The introductory paragraph discourages the Interruption of any Demand, implying that no Demand directly connected should be interrupted. However, it is an acceptable practice to allow for some Interruption of Demand that is directly connected to the element that is removed from service. Recommend that the drafting team revise the wording to eliminate this implication, and soften the expectation such that it is recognized that some Interruption of Demand is unavoidable by system configuration, but that each entity should establish a reasonable limit on how much demand can be interrupted due to the loss of an element. 2. The Statement that "However, Demand may need to be interrupted in limited circumstances to address BES performance requirements" in the introductory paragraph contradicts bullet 3 "Demand that does not adversely affect BES ..." 3. The third Bullet is confusing. Suggest revising the wording to clarify the adverse impact to the BES system, documentation expectations, and to answer fundamental questions such as who has the authority to decide the use if the stakeholder process is "accepting", and the necessity of having a stakeholder process. It is unlikely that the interruption of Demand will adversely impact the BES system. This constraint is too broad. The language in this bullet also allows that non-consequential Demand interruption could be used to mitigate reliability violations arising from the NERC Category B contingency events (i.e., single element contingencies). 4. In the second paragraph, the conditions when interruption of Firm Transfers may be used are not specified. 5. In the last sentence of the second paragraph, "would" should be replaced by "must". Alternatively, possible rewording of footnote "b" to be considered: b) An objective of the planning process should be to minimize the likelihood of interrupting Demand and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements or other local reasons which have no adverse impact on overall BES reliability or the interconnected BES. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Demand that does not adversely impact overall reliability of the BES or the interconnected BES and where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of available resources, where it can be demonstrated that Facilities remain within

Organization	Yes or No	Question 1 Comment
		applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected. The Drafting Team should reconsider the use of "Load" as opposed to "Demand". By definition (NERC Glossary dated April 20, 2010) Demand is:"1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer."Load is defined as:"An end-use device or customer that receives power from the electric system."This terminology is more appropriate to the application used in the Table.
SERC Planning Standards Subcommittee	No	The revised text relating to the planning process exceeds what is appropriate for a reliability standard. Existing open and transparent stakeholder processes focus on larger system issues and not on local load serving. We suggest the following: Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Interruptible Demand or Demand-Side Management o Demand that does not adversely impact overall BES reliability and is made temporarily radial as a result of the Contingency, where that Demand must be interrupted to meet performance requirements. Curtailment of firm transfers is allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected. " The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers."
Ameren	No	The revised text to footnote b relating to the planning process exceeds what is appropriate for a reliability standard. Existing open and transparent stakeholder processes focus on larger system issues rather than on local load serving issues. We suggest the following text for footnote b:Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Interruptible Demand or Demand-Side Management o Demand that does not adversely impact overall BES reliability and is made temporarily radial as a result of the Contingency, where that Demand must be interrupted to meet performance requirements. Curtailment of firm transfers is allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the

Organization	Yes or No	Question 1 Comment
		re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected.
MRO's NERC Standards Review Subcommittee	No	The revised draft is a significant improvement over the first draft. However, we suggest the following minor changes: 1. The criterion of “adversely affect overall BES reliability” is undefined and maybe subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest adding the words “as defined by each Transmission Planner or Planning Authority”. 2. The term of “firm transfers” is undefined and maybe subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest establishing a definition for the term, reverting to the “Firm Transmission Service” term, or using another appropriate defined term.
American Transmission Company	No	The revised draft is a significant improvement over the first draft. However, we suggest the following minor changes: 1. The criterion of “adversely affect overall BES reliability” is undefined and may subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest adding the words “as defined by each Transmission Planner or Planning Authority”. 2. The term of “firm transfers” is undefined and may subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest establishing a definition for the term of "firm transfers", reverting to the “Firm Transmission Service” term, or using another appropriate NERC defined term.
PacifiCorp	No	PacifiCorp believes that the current version of footnote “b” is an improvement over the language that currently exists in the standard, except for one component of the revised footnote. The third bullet in the draft standard currently limits the interruption of Demand if it does not adversely impact overall BES reliability, where the circumstances describing the use of the interruption are documented (including alternatives evaluated) and the application is subject to review and acceptance in “an open and transparent stakeholder process.” PacifiCorp believes that the language requiring review and acceptance of an application of demand interruption through any sort of stakeholder process should be removed. It is not practical or effective to prescribe that either this standard or any other standard requires stakeholder approval in order to maintain compliance. As presently drafted, this requirement for stakeholder review and acceptance appears to be inconclusive and indeterminate as to what is required for registered entities to comply. Instead, this third bullet should require the documentation, by the Planning Authority and Transmission Planner, of the circumstances describing the use of Demand interruption - including methodologies used, assumptions relied upon, and alternatives evaluated - as part of the Planning Authorities’ and/or Transmission Planners’

Organization	Yes or No	Question 1 Comment
		documentation of results in their annual Reliability Assessments. These annual assessments are already submitted to the appropriate Regional Reliability Organization pursuant to TPL-002-1b Requirement R3. This annual assessment can be provided by the ERO to other appropriate third parties upon their request.
Southern Company	No	The revised text relating to the planning process exceeds what is appropriate for a reliability standard. Existing open and transparent stakeholder processes focus on larger system issues and not on local load serving. We suggest that the drafting team go back to the concept of local load being the load that is made temporarily radial by the contingency. That was a much better approach.
JEA	No	The requirement in general is acceptable; however, there needs to be an added "such as" clause to the referenced "...in an open and transparent stakeholder processes." I suggest adding "..."...in an open and transparent stakeholder processes such as the FERC approved regional 890 process that includes the load serving entity affected".
South Carolina Electric and Gas	No	SCE&G believes the first sentence "An object of the planning process is to avoid interruption of Demand." goes beyond what is appropriate for a reliability standard and therefore should be deleted. Also, the part of the sentence that states "and where the application is subject to review and acceptance in an open and transparent stakeholder process" goes beyond what is appropriate for a reliability standard and should be deleted.
NorthWestern Energy	No	In addition to the three bullet items, add a fourth bullet item to the list of limitations under the body of footnote b: "In no case will a total loss of load that is less than 50 MW be considered a violation of this standard."
TVA Transmission Planning & Compliance	No	TVA supports FERC's actions on improving reliability of the BES; however, TVA believes that the new proposal is focusing more on reliability of local loads than on the overall reliability of the BES. Footnote b should focus only on the overall reliability of the BES. Reliability of local loads should be addressed outside the TPL standards and therefore should not be used/referenced in footnote b. Also existing stakeholder processes (referred to in the SDT proposal) typically focus on larger system issues and not on local load serving. Thus TVA believes that some local load should be allowed to be dropped in order to maintain BES reliability. However TVA does believe that there should be a limit of how much load can be dropped in order to maintain BES reliability. TVA believes that 50 MW is a reasonable number for this limit. Based on the above, TVA proposes substituting the following for the revised footnote b:Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: Demand that is directly served by the elements that are removed from service as a result of the Contingency Interruptible Demand or Demand-Side Management Demand that does not adversely impact overall BES reliability, where that Demand (not to exceed 50 MW)

Organization	Yes or No	Question 1 Comment
		must be interrupted to meet performance requirements. Curtailment of firm transfers is allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected.
BC Hydro	No	The SDT is to be commended for their efforts to develop clear, unambiguous language for Footnote “b”. From the discussions that have taken place it seems that there are many different perspectives and to get agreement on specific language will be very difficult. We believe that it would be useful to identify the main issues that Footnote “b” needs to address and we consider those main issues to be: o Definitions of (a) Consequential Load Loss, (b) Firm Demand, (c) Firm Transmission Capability (as distinct from the OATT term, “Firm Transmission Service”), (d) Firm Transfer (this could be defined as transfers using the OATT’s Firm Transmission Service, (e) Manual System Adjustments (capitalized in the Category C section of TPL-001, but not defined in the NERC Glossary) and (f) the Bulk Electric System (BES). o Identifying permissible Demand/Transfer curtailment actions for (a) the planning studies simulating the Category B event itself and (b) the planning studies associated with determining acceptable actions for preparing for the next set of contingencies should the initial single contingency be prolonged (ie, last several weeks). This would define the acceptable (pre-emptive) “Manual System Adjustments” of Category C events. o Define separate acceptable curtailment actions for (a) curtailment of Demand (ie, end-user load) and (b) curtailment of market to market transfers, that very rarely, if ever, result in the loss of any end-user load. o Define the planning studies required to determine the acceptability of the impacts on the BES resulting from curtailments in a “remote” part of the system that have been accepted by those directly affected by those curtailments. At this point we don’t have specific language to suggest, but we do have the following comments that we hope will help: A. Interruption of Demand: A.1. Consider improving the definition of “Firm Demand” in the NERC Glossary that now reads, “That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions”. Perhaps it could be changed to something like, “That portion of the Demand that the planned transmission system must be able to supply without interruption for Category B events. A.2. Consider stating in Footnote “b” that curtailment of Firm Demand is (a) not permitted in the simulation of the N-1 event itself and (b) it is not permitted as part of the (pre-emptive) “Manual System Adjustments” needed to prepare for the next set of contingencies should the initial single contingency be prolonged (ie, last

Organization	Yes or No	Question 1 Comment
		several weeks). B. Interruption of Firm Transfers: B.1. "Firm Transfers" could be defined as transfers using the OATT's Firm Transmission Service, but consider developing a system reliability-based term for "Firm Transmission Capability" instead of referring to the tariff-based NERC definition of "Firm Transmission Service". This would recognize the difference between planning standards and commercial/tariff rules. The NERC definition of "Firm Transmission Service" is now, "The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption". Transmission tariffs address the priority of curtailments when the loading on a transmission path needs to be reduced for whatever reason (single- or multiple-contingencies). The NERC transmission planning standards need a system reliability definition like, "Firm Transmission Capability" is the transmission capability across a cut-plane, on a defined transmission path or across a defined flowgate that is available, before any manual corrective actions are taken, following the worst Category B event under the most onerous normal system conditions considering all plausible generation dispatch patterns and the full range of expected load levels." B.2. Consider stating in Footnote "b" that curtailment of Firm Transfers is only permitted to the extent that redispatch of generation can be implemented so that delivery to the Firm Transfer recipient is not interrupted (a) in the planning studies of the Category B event itself and (b) as part of the (pre-emptive) "Manual System Adjustments" needed to prepare for the next set of contingencies should the initial single contingency be prolonged (ie, last several weeks). C. General Comments: C.1. Consider replacing the first bullet of the proposed Footnote "b" with simply "Consequential Load Loss" since the NERC Project 2006 02 (TPL 001) Standard Drafting Team is introducing the following definition: Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault C.2. Consider removing "Demand-Side Management" (DSM) from the second bullet because that term is too general. The present definition of DSM in the NERC Glossary is:"The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use". C.3. Consider being more specific on what constitutes acceptable "Interruptible Demand", like: "Interruptible Demand that is part of an automatic real-time Direct Control Load Management (DCLM) system that is activated by the contingencies that require it and that is a completely "dual-redundant" scheme including all communications equipment. The DCLM system must result in automatic curtailment of Demand that is fast enough to maintain all BES system performance standards (eg, voltage stability, voltage dip, etc)".

Organization	Yes or No	Question 1 Comment
		C.4. Consider eliminating the description of how interrupting Demand that does not adversely impact overall BES reliability was accepted (ie, the stakeholder process, etc). If such a process were undertaken and it resulted in acceptance that the Demand could be curtailed for Category B events, wouldn’t that simply mean that the Demand was “Interruptible Demand”. It really doesn’t matter what process resulted in it being accepted. The key considerations are that (a) if the interruption of that Demand is necessary to maintain BES reliability, then it must be interrupted in a very reliable manner (ie, dual redundant scheme, etc) and (b) if the interruption of that Demand is not necessary to maintain the reliable performance of the BES, then that should be confirmed by the planning studies (ie, it doesn’t need to have an expensive, sophisticated, dual-redundant DCLM scheme since the impact on the BES is acceptable even if the scheme doesn’t work). D. Additional Questions related to Curtailment of Firm Transfers: In the past, the latter part of Footnote B read: “To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.”The last part of the proposed Footnote B now reads: “Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected.”We would like to understand the implications of the proposed Footnote B as it relates to curtailment of Firm Transfers (as per definition proposed earlier) for the following questions: 1) In the most recent draft of Footnote B, why was the NERC defined term ‘Firm Transmission Service’ replaced with the non-defined term ‘firm transfers’? 2) In the most recent draft of Footnote B, why was the tone softened from “No curtailment of Firm Transmission Service is allowed, except...” to “Curtailment of firm transfers is allowed when...”? 3) Assuming an outage of a single transmission line (N-1 Category B event) has occurred and assuming that no “resources [are] obligated to redispatch” for this outage, would a transmission provider be allowed to curtail Firm Transmission Service (NERC defined term) that it has sold in order to prepare to withstand the next worst credible contingency? 4) Would transmission providers be allowed to sell Firm Transmission Service on a path above what could be delivered with any one element of that path out of service and a range of operating conditions? 5) If the proposed Footnote B is approved, would utilities have to reinforce their system (within 60 months) to ensure that Firm Transmission Service for particular paths would not be curtailed can be delivered when any one element of that path is out of service? 6) If a transmission provider employs Generation Dropping for single contingencies in order to support Firm Transmission Service between regions, and assuming there are no provisions for obligated re-dispatch, would

Organization	Yes or No	Question 1 Comment
		the proposed Footnote B force a recalculation of firm vs non-firm transfer capability? 7) Path 66 (PACI) and Path 65 (PDCI) can both see significant derates in their firm transfer capability for single contingencies. How would the proposed Footnote B impact Firm Transmission on these paths?
FirstEnergy	No	FirstEnergy appreciates the efforts of the Assess Transmission Future Needs SDT in reaching a reasonable proposal for clarifying Table 1 footnote B presented in the TPL-001 through TPL-004 standards. We also commend NERC staff for convening an industry technical conference to discuss the topic and FERC staff for their participation in the technical conference as the industry carefully considered various perspectives. The proposed footnote B is much improved from the prior draft proposals. One change that FirstEnergy proposes is to strike the text following the semicolon in the third bullet item which states "and where the application is subject to review and acceptance in an open and transparent stakeholder process." This text may be intended as explanatory but has the appearance of mandating an approval process that will be auditable through the TPL reliability standards. The statement is not needed within the framework of mandatory reliability requirements as FERC Order 890 already mandates an open and transparent process related to the planning of the bulk electric system. FERC via the 890 Final Rule modified the pro forma Open-Access Transmission Tariff to require open and transparent stakeholder process to better ensure no undue discrimination and access to the transmission system. The Final Rule beginning at paragraph 418 discusses reform to the Coordinated, Open and Transparent Planning of the transmission system. The Commission direction included eight planning principles required to be within the open process - one of which is dispute resolution. It should be well understood that the transmission planner and planning coordinator share and disseminate all of their planning study results and proposed corrective actions - including the proposed use of Demand interruption - as part of their adherence to Order 890. We appreciate the SDT's careful consideration of our comments.
Northeast Utilities	No	NU agrees with the language of the proposed revision to Footnote b EXCEPT FOR bullet #3 which suggests that non-consequential demand interruption could be used to mitigate reliability violations arising from the NERC Category B contingency events (i.e., single element contingencies).
ERCOT	No	The introductory paragraph of footnote b includes policy language. Since this is a reliability standard-and not a policy directive-the general narrative setting forth the desired policy goal of minimizing load-shedding is misplaced. Including policy language can cloud the specific issues the standard attempts to address, and ERCOT recommends deleting the first two sentences in the introductory paragraph. The next sentence in the introductory paragraph goes on to state, generally, that demand may be interrupted to "address BES performance requirements." This phrase is vague. To which performance requirements does this refer? The intent is not clear. If the intent is to generally recognize the need to shed load to respect

Organization	Yes or No	Question 1 Comment
		NERC standards and to allow flexibility for an entity to exercise discretion relative to meeting BES performance requirements, then that intent should be clearly reflected in the language. Furthermore, the last sentence of the introductory paragraph and the subsequent bullet points are arguably inconsistent with this approach, because they could be viewed as removing an entity’s flexibility/discretion by limiting the circumstances when load can be shed. The second bullet point is unnecessary, because it is already apparent that interruptible demand/demand side management programs can be used according to their terms. This could create confusion in that it could be implied that, absent the need to use these to meet BES performance requirements, using them otherwise is inconsistent with/not allowed under footnote b. Simply put, those products are not load shedding as contemplated by this footnote. Therefore they should not be listed here. With respect to the third bullet point, the phrase "demand that does not adversely impact overall BES reliability" is not adequately defined, and provides opportunity for confusion. This is an ambiguous phrase and can’t be linked back to objective NERC standards/requirements. The bullet points should avoid ambiguity to mitigate ambiguity risk in audits. In addition, the last part of the language in this bullet imposing an open and transparent stakeholder process is unclear. What is the intent behind requiring review in a stakeholder process? If it is to establish the ability of the entity to develop load shedding procedures beyond those explicitly contemplated in footnote b, ERCOT questions if it is reasonable for the responsible entity to be required to get “permission” from stakeholders to implement reliability measures related to its obligation as the functional entity. Again, the language simply is not clear. Accordingly, ERCOT recommends this bullet point be removed. If it is retained, it should be revised consistent with these comments to remove ambiguous language to mitigate potential confusion around the meaning/scope of the footnote in the administration of the CMEP. In addition, ERCOT recommends revising the draft footnote b to allow for planned Demand interruption as a means of mitigation during interim periods when a unanticipated (such as unexpected demand growth or unit retirements) or temporary change on the system occurs in a timeframe that is shorter than the time necessary to plan and implement the system upgrades necessary to avoid the Demand interruption. Finally, in the last paragraph of footnote b, it isn’t clear why “Transmission Service” was changed to “transfers.” Firm transmission service is a service provided in some regions, and it provides relative value to other types of services-e.g., non-firm and network. The mention of transmission service may also be irrelevant in this footnote, since the allowance of its interruption doesn't also allow for load shedding. Therefore, ERCOT recommends eliminating the last paragraph of footnote b.
ISO New England Inc.	No	ISO New England does not allow non-consequential load loss for first contingencies in Planning Analysis, and as an overall matter, ISO-NE believes that the appropriate step is for NERC to modify the footnote in line with

Organization	Yes or No	Question 1 Comment
		the original FERC Order. However, ISO-NE offers the following recommendation to improve the proposed language for footnote b if it is to be retained similar to what has been proposed. In short, ISO-NE proposes changing the third sub-bullet, because the provision is both unnecessary and inappropriate for a NERC Standard. First, the sub-bullet is redundant, because the Commission has ordered that companies add to their Open Access Transmission Tariffs an open and transparent planning process. If Transmission Planners establish their system planning assessments through those processes, then there should be no question that the Planner's assessments have been effectively communicated to the region. Second, the passive nature of the language (i.e., "where the application is subject to review and acceptance...") is unclear as it suggests that someone other than the Planning Coordinator/Transmission Planner is responsible for determining what belongs in a long-term system assessment. Including Demand-Side Management in the standard also appears redundant as Demand Response is used as an asset in the same manner as generation resources. b) When interruption of Demand is utilized within the planning process, such interruption is limited to: 1) Demand that is directly served by the elements that are removed from service as a result of the Contingency. 2) Interruptible Demand or Demand-Side Management 3) Instances where the planned or controlled interruption of Demand results in System performance which meets the requirements of Table 1 for Category B contingencies. When such Demand interruption is utilized in an assessment, the use of such actions must be limited to small portions of the system, be operationally achievable, be of limited duration, and be documented therein.
Entergy Services	No	Entergy disagrees with the proposed language in the third bullet for two reasons. 1. While Entergy supports the idea of "an open and transparent stakeholder process" regarding the use of non-consequential load loss. It is unclear how such a process could be fairly implemented as competing stakeholder interests could prevent resolution. Stakeholders should be defined as those stakeholders whose load could be shed per footnote b, not any and all stakeholders. 2. The "is subject to review and acceptance" implies that some formal voting process would be required by stakeholders. Is this the SDT's intent? If so would such a process be developed as part of the standard or would it be left up to TO's? If non-consequential load loss was deemed an acceptable solution across a SEAM, would the TO's jointly serving the load need to agree?

Organization	Yes or No	Question 1 Comment
MidAmerican Energy	No	While the TPL note "b" approach has improved, MidAmerican has concerns that including the wording "review and acceptance" goes beyond the FERC Order 890 order, process, and intent of including the open review process. Therefore, to align with FERC Order 890, the "review and acceptance" should be replaced with "subject to comment". Anything more exceeds FERC Order 890 and the reason why the review process was included. In the end, Transmission Owning and Operating entities must have final say in the operation of the grid. Entities can comment, but cannot obstruct Transmission Owning and Operating entities from properly operating the grid or reliability could be reduced.
United Illuminating Co	No	United Illuminating believes that for TPL Category B contingencies no planned or controlled (non-consequential) interruption of firm demand should occur as a general philosophy for planning the Bulk Electric System (BES). Recognizing there are certain areas of the BES that have unique circumstances that may warrant an exception to this, UI suggests the addition of language that recognizes the limited application of non-consequential load interruption with a process that requires a case-by-case acceptance of such application by the Regional Entity or NERC.
New York Independent System Operator	Yes	The NYISO agrees in principle with the proposed changes, but recommends the following modifications: 1. The introductory paragraph discourages the Interruption of any Demand, implying that no Demand directly connected should be interrupted. However, it is an acceptable practice to allow for some Interruption of Demand that is directly connected to the element that is removed from service. The introductory paragraph is immaterial to the requirement, and therefore unnecessary with the exception of the last sentence which starts the bulleted list. 2. Interruptible demand is an operation tool and not a transmission planning tool, while Demand-Side Management is typically embedded in the load forecast used in the planning process. The second bullet therefore may not be necessary or applicable here, though it is helpful in making clear those are acceptable forms of interruption. 3. The third bullet is confusing. Suggest revising the wording to clarify the adverse impact to the BES system and documentation expectations. Recommend removing reference to the application being subject to review and acceptance in an open and transparent stakeholder process; this is inherent to all documentation and does not need to be emphasized in a footnote. 4. In the last sentence of the last paragraph, "would" should be replaced by "must". 5. The Drafting Team should reconsider the use of "Load" as opposed to "Demand". By definition (NERC Glossary dated April 20, 2010) Demand is: 1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer."Load is defined as:"An

Organization	Yes or No	Question 1 Comment
		end-use device or customer that receives power from the electric system.”This terminology is more appropriate to the application used in the Table. Possible rewording of footnote “b” to be considered: b) Under the limited circumstances when interruption of Load is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Load that is directly served by the elements that are removed from service as a result of the Contingency o Interruptible Load or Demand-Side Management o Demand that does not adversely impact overall BES reliability where the circumstances for the use of such Load interruption and alternatives evaluated are documented. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of available resources, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions must also be respected.
Midwest ISO	No	Overall, we believe the changes are reasonable. However, we propose to strike "and where the application is subject to review and acceptance in an open and transparent stakeholder process.” Stakeholder review processes should not be mandated through enforceable standards as they do not provide a clear benefit to reliability. Further, FERC Order 890 already mandates an open and transparent process related to the planning of the bulk electric system.
GDS Associates Inc.	No	We appreciate all the work conducted by SDT to adjust current footnote “b” however, we disagree with the current approach as follows below:- The definition does not go far enough with recognition that interruption of Demand should be mitigated if at all possible. The previous language may have been inadequate, but the current language does not encourage the TP to develop mitigation plans that could be implemented as an alternative to Demand interruption. - Use of Interruptible Demand should only be implemented if the Transmission Planner can point to a contract between the Transmission Provider and Transmission Customer that permits load curtailment .- Under FERC Order 890, Conditional Firm transmission service can be granted for entities who voluntarily acknowledge the right of the Transmission Provider to curtail their transaction or provide re-dispatch. This should be the only transfer which can be utilized in the Planning Horizon for interruption of Demand for Note b. Suggested language to find the balance point in the tone of this note is below:”An objective of the planning process is to develop mitigation plans that do not call for the curtailment of Demand, as interruption of Demand places specific customer groups at a reliability risk that varies from their counterparts in other areas of the BES. There may be rare instances, however, where interruption of Demand can be considered a short-term bridge to a mitigation plan which does not rely on negatively impacting certain customer segments. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency, o

Organization	Yes or No	Question 1 Comment
		Interruptible Demand or Demand-Side Management, where the Customer has given explicit rights to the Transmission Provider for curtailment of their Demand, o Demand, other than Interruptible Demand or Demand-Side Management, that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand are documented, including alternatives evaluated; where the Load-Serving Entity who has responsibility for serving such Demand has agreed to the curtailment, and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of Firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch per the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of and firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected. In addition, any Conditional Firm transfers may be curtailed, in accordance with the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider."
Kansas City Power & Light	No	KCPL appreciates the efforts of the Assess Transmission Future Needs SDT in reaching a reasonable proposal for clarifying Table 1 footnote B presented in the TPL-001 through TPL-004 standards. We also commend NERC staff for convening an industry technical conference to discuss the topic and FERC staff for their participation in the technical conference as the industry carefully considered various perspectives. Although the proposed footnote B is much improved from the prior draft proposals, KCPL proposes is to strike the text following the semicolon in the third bullet item which states "and where the application is subject to review and acceptance in an open and transparent stakeholder process." This text may be intended as explanatory but has the appearance of mandating an approval process that will be auditable through the TPL reliability standards. The statement is not needed within the framework of mandatory reliability requirements as FERC Order 890 already mandates an open and transparent process related to the planning of the bulk electric system. FERC via the 890 Final Rule modified the pro forma Open-Access Transmission Tariff to require open and transparent stakeholder process to better ensure no undue discrimination and access to the transmission system. The Final Rule beginning at paragraph 418 discusses reform to the Coordinated, Open and Transparent Planning of the transmission system. The Commission direction included eight planning principles required to be within the open process - one of which is dispute resolution. It should be well understood that the transmission planner and planning coordinator share and disseminate all of their planning study results and proposed corrective actions - including the proposed use of Demand interruption - as part of their adherence to Order 890.
Puget Sound Energy	Yes	PSE agrees with the foot note b as stated. As it states for any category B outage there wouldn't be any non-consequential load loss allowed unless a full study is performed with evaluation of alternatives and is approved by stakeholders. Also, one could curtail firm transfers if re-dispatch of resource is possible.

Organization	Yes or No	Question 1 Comment
		However, there is still some ambiguity in when approval from stakeholders (time-line) should be sought and who the stakeholders could be (customers, effected utilities etc.). Hence, PSE would like to revise the footnote by adding the following to the end of the footnote, ".... at least 2 years prior to the implementation. All the affected parties must review and agree upon the loss of demand proposal."
Southern California Edison Company	Yes	SCE appreciates the efforts of the NERC Standards Drafting Team and believes that the team has admirably worked to meet FERC's expectations.SCE would suggest that Footnote "b" be revised to include a semi-colon(;) after the first sub-paragraph and a semi-colon(;) followed by an "and" after the second sub-paragraph, to convey that the three sub-paragraphs are alternative, rather than additive methods for satisfying the requirements for "interruptions."
Idaho Power	Yes	footnote 'b' is silent with respect to planned removal from service of certain generators. I believe there are many conditions out there where a single contingency can initiate a planned (RAS-initiated) removal of generation. The fact that this is mentioned in footnote 'c', under multiple contingencies, begs the need for futher elaboration/discussion of this option under single contingencies in footnote 'b'.
Manitoba Hydro	Yes	The changes to Table 1 Note b proposed by the SDT for this second posting are a reasonable approach to the issue of interrupting of "Firm Demand". The requirement to evaluate alternatives to dropping of Firm Demand in a transparent stakeholder process should provide the verification of cost over benefit on a case by case basis. I propose the following editorial changes: 1. The change of "Firm Transmission Services" made in Table 1 should be also be made in each TPL standard as R1 refers to "projected Firm (non-recallable reserved) Transmission Services.2. Since "Firm Demand" is a defined term, ensure it is capitalized throughout the standard. There is one instance where it is not.
California ISO	Yes	1) Regarding the 2nd bullet provision, we suggest: Interruptible Demand or Demand-Side Management that has been reviewed and approved by the Planning Authority. 2) Regarding the 3rd bullet provision, we suggest: Demand interruption that does not adversely impact overall BES reliability.... 3) Also regarding the 3rd bullet provision, we suggest replacing acceptance with clarification to read "where the application is subject to review and clarification in an open and transparent stakeholder process."
Xcel Energy	Yes	Xcel Energy supports the new interpretation that would allow curtailment of firm transfers or demand for limited conditions where the integrity of bulk electric system is not compromised. However Xcel Energy seeks some clarification regarding the following: The 3rd bullet point in footnote b will need to clarify whether the demand interruption can be done after the contingency, or before the contingency. If it is allowed after the

Organization	Yes or No	Question 1 Comment
		contingency, then the standard would allow violation of voltage or thermal loading criteria for a brief period, after contingency and, before demand curtailment happens. Is this acceptable based on the new interpretation? Since TPL-002 standard deals with NERC Category B contingencies, and footnote b states that curtailment of firm transfers is allowed, it should be clarified if this curtailment is allowed before or after the contingency. If the curtailment is allowed only after the contingency, then the system would be in violation of the thermal or voltage criteria for a brief period till the generation is re-dispatched. Is this allowed by the new interpretation? If curtailment is only allowed in preparation of the contingency, then the firm transfers would be curtailed during system intact conditions, in preparation for the first contingency, resulting in violation of TPL-001 standard. Is this allowed by the new interpretation?
PPL Corp	Yes	PPL believes that Footnote b as described in TPL-002-1b, Draft 2, August 30, 2010 is fine provided an accompanying Requirement (with appropriate VRF and VSL) and Measure is added to the TPL standard(s) to require and document notification of the affected Demand parties and the involvement of the affected Demand parties in an open process as described by Footnote b, third bullet.
Duke Energy	Yes	Duke Energy strongly supports this revised footnote ‘b’. We believe that it provides for appropriate consideration of stakeholder input in decision-making for local reliability issues, while maintaining the reliability of the Bulk Electric System.
ITC	Yes	The proposed language for the new TPL-001-1 Table 1 footnote b is acceptable to ITC.
Bonneville Power Administration	Yes	
Dominion	Yes	
IRS Standards Review Committee	Yes	
IRC Standards Review Committee	Yes	
Arizona Public Service Company	Yes	
ERCOT ISO	Yes	

Organization	Yes or No	Question 1 Comment
Georgia Transmission Corporation	Yes	
American Electric Power	Yes	
Independent Electricity System Operator	Yes	
Pacific Gas and Electric Co.	Yes	

Consideration of Comments on TPL Table 1 Order — Project 2010-11

The TPL Table 1 Order Drafting Team thanks all commenters who submitted comments on the 3rd posting for Project 2010-11: TPL Table 1 Order. These standards were posted for a 45-day public comment period from November 19, 2010 through January 5, 2011. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 27 sets of comments, including comments from more than 67 different people from approximately 30 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

The SDT reviewed all of the comments received and has made a clarifying change to the structure of the footnote to address industry concerns as to the intent of the SDT. No contextual changes have been made to the footnote. Therefore, the SDT is recommending that this project be moved to a recirculation ballot.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

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

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

Index to Questions, Comments, and Responses

The Industry Segments are:

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

Additional Member	Additional Organization		Region	Segment Selection
1.	Al Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Dean Ellis	Dynegy Generation	NPCC	5
8.	Brian Evans-Mongeon	Utility Services	NPCC	8
9.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	Chantel Haswell	FPL Group, Inc.	NPCC	5
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

14.	Michael R. Lombardi	Northeast Utilities	NPCC	1
15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

				1	2	3	4	5	6	7	8	9	10
2.	Group	Charles W. Long	SERC Planning Standards Subcommittee	X									X

Additional Member		Additional Organization	Region	Segment Selection
1.	Pat Huntley	SERC Reliability Corporation	SERC	10
2.	Bob Jones	Southern Company Services	SERC	1
3.	Darrin Church	Tennessee Valley Authority	SERC	1
4.	Jim Kelley	PowerSouth Energy Cooperative	SERC	1
5.	John Sullivan	Ameren Services Company	SERC	1
6.	Phil Kleckley	South Carolina Electric & Gas Co.	SERC	1

				1	2	3	4	5	6	7	8	9	10
3.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4.	Jason Marshall	Midwest ISO Inc.	MRO	2
5.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
6.	Ken Goldsmith	Alliant Energy	MRO	4
7.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
8.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Eric Ruskamp	Lincoln Electric System	MRO 1, 3, 5, 6										
10.	Joseph Knight	Great River Energy	MRO 1, 3, 5, 6										
11.	Joe DePoorter	Madison Gas & Electric	MRO 3, 4, 5, 6										
12.	Scott Nickels	Rochester Public Utilties	MRO 4										
13.	Terry Harbour	MidAmerican Energy Company	MRO 1, 3, 5, 6										
14.	Richard Burt	Minnkota Power Cooperative, Inc.	MRO 1, 3, 5, 6										
4.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
5.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
6.	Individual	Andy Tillery	Southern Company	X		X							
7.	Individual	Aaron Staley	Orlando Utilities Commission	X				X					
8.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
9.	Individual	Si Truc PHAN	Hydro-Quebec TransÃ‰nergie	X									
10.	Individual	Tim Ponseti, VP	TVA Trasnmission Plannning & Compliance	X		X		X				X	
11.	Individual	Alex Rost	New Brunswick System Operator		X								
12.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
13.	Individual	Bernie Pasternack	Transmission Strategies, LLC								X		
14.	Individual	Michael A. Curtis, General Counsel	Mohave Electric Cooperative			X							
15.	Individual	David Thorne	Pepco Holding Inc	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
16.	Individual	John Sullivan	Ameren	X		X		X	X				
17.	Individual	Thad Ness	American Electric Power	X		X		X	X				
18.	Individual	Bob Casey	Georgia Transmission Corporation	X									
19.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
20.	Individual	Saurabh Saksena	National Grid	X		X							
21.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
22.	Individual	Jason L. Marshall	Midwest ISO		X								
23.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
24.	Individual	Dan Rochester	Independent Electricity System Operator		X								
25.	Individual	Gregory Campoli	New York Independent System Operator		X								
26.	Individual	Kathleen Goodman	ISO New England Inc		X								
27.	Individual	Harold Wyble	Kansas City Power & Light	X		X		X	X				

1. The SDT is proposing a revision to footnote 'b' in the TPL tables to comply with a FERC directive which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.

Summary Consideration: The SDT reviewed all of the comments received and has made a clarifying change to the structure of the footnote to address industry concerns as to the intent of the SDT. No contextual changes have been made to the footnote.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized [llh1]that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

Organization	Yes or No	Question 1 Comment
SERC Planning Standards Subcommittee	No	The PSS agrees that the proposed language for footnote b provides some additional clarity. While we generally support the concept, we have concerns that the phrase "is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments" remains ambiguous and should be clarified by limiting stakeholder input to those who have load at risk or local regulators obligated to

Organization	Yes or No	Question 1 Comment
		act on their behalf. Revise the first sentence of the last paragraph to read: "To prepare for a second contingency, curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand."The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Response: The stakeholder process needs to be open and transparent but it is up to the entity to establish the process and whom it may include. No change made. As drafted, footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. It further clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the footnote. No change made.		
Xcel Energy	No	As this is currently drafted, planners would be required to host a forum with stakeholders to discuss hypothetical actions that may be taken in an emergency. We do not see the value in this, nor is it clear who would be considered stakeholders that should attend this forum. For example, we assume it would be the transmission owner's meeting with distribution providers to discuss the possibility of load shedding. Would that be adequate? Xcel Energy is both a Transmission Planner and a Distribution Provider. In this case would the stakeholder be the end user? This should be struck or more clearly defined.
Response: The stakeholder process needs to be open and transparent but it is up to the entity to establish the process and whom it may include. No change made.		
New York Independent System Operator	No	1. Proposed revised footnote language:b) It is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Interruptible Demand or Demand-Side Management o Circumstances where the uses of firm Demand interruption not directly interrupted by the contingency are documented, including alternatives evaluated; and where the firm Demand interruption is subject to review in an open and transparent stakeholder process. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities

Organization	Yes or No	Question 1 Comment
		remain within applicable Facility Ratings and the re-dispatch does not result in the interruption of any firm Demand. 2. Comments:There are generic concerns with the footnote as amended that must be addressed. The first is the use of the term "Demand". It is very unclear throughout the footnote whether or not the term Demand includes Interruptible Demand or Demand-Side Management. It is suggested that interruption of Demand be clarified to not include Interruptible Demand or Demand-Side Management to more clearly show the permitted use of that option for load shedding. 3. Further confusion is introduced through the use of the term "firm Demand" in some locations. It is unclear how this is different than the defined term "Firm Demand" and what the implications of the term "firm Demand" are. 4. The first and third sentences of the first paragraph are unnecessary and should be deleted. However, if they are to be retained, the first sentence is unacceptable in its current state. In some instances, Interruptible Demand or Demand-Side Management are utilized in lieu of transmission additions. These can be considered as acceptable mitigation and there is no justification to minimize their use. Therefore some clarification to the term Demand in the first sentence must be made. 5. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. 6. The second portion of the second bullet should be deleted as it is unncessary: "and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments." If this is to be retained, the very last portion should be deleted "that includes addressing stakeholder comments". The term "addressing" is unclear. This can be misconstrued to infer that plans must be changed in response to stakeholder comments. This may be inappropriate and may be impossible if conflicting comments are received. It may also create a new standard that all comments must be "addressed", which may not be a part of the stakeholder process across NERC's footprint. 7. The first sentence of the paragraph under the two bullets seems to prevent a situation where a combination of re-dispatch and the interruption of Demand are utilized. This restriction could prevent a situation where the use of re-dispatch decreases the amount of Demand which must be interrupted. This footnote should not discourage such adjustments which actually increase the reliability of service to end users. 8. This same sentence also uses the term "shedding of firm Demand". This should be replaced with "Demand interruption" such that it is consistent with the second bullet; otherwise an unnecessary new term has been introduced.

Organization	Yes or No	Question 1 Comment
		9. The last sentence of footnote B is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple NERC standards if it was added here, otherwise it would infer that such actions are acceptable in all other standards.

Response: 1. See response to National Grid #1 in ballot comment responses.

2. See response to National Grid #1 in ballot comment responses.

3. See response to National Grid #6 in ballot comment responses.

4. The SDT has reorganized the footnote to clarify its intent and address the issues raised.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result~~ [llh2]~~in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

5. See response to National Grid #2 in ballot comment responses.

6. See response to National Grid #4 in ballot comment responses.

7. The SDT has reorganized the footnote to clarify its intent and address the issues raised.

8. The SDT has reorganized the footnote to clarify its intent and address the issues raised.

Organization	Yes or No	Question 1 Comment
9. See response to National Grid #7 in ballot comment responses.		
ISO New England Inc	No	1. The following comments are provided in regard to this proposal. The first and third sentences of the first paragraph are unnecessary. While we agree with the concept, it is unclear as to how inclusion of these sentences in a standard creates a measureable requirement. 2. There are generic concerns with the footnote as currently proposed. The first is the use of the term "Demand." It is unclear whether the term Demand includes Interruptible Demand and Demand-Side Management. It is suggested that interruption of Demand be clarified to exclude Interruptible Demand and Demand-Side Management to more clearly show the permitted use of those options. 3. The second concern is that it is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. 4. The third is that not all areas have stakeholder processes. Documenting the use of Demand Interruption should be sufficient without requiring stakeholder review. Therefore the second portion of the second bullet "including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments" is unnecessary and should be deleted. "Addressing stakeholder comments" introduces undefined actions which may be required in response to the comments. For those areas that already have stakeholder processes, stakeholder comments are by definition addressed. As a result, at a minimum "that includes addressing stakeholder comments" should be deleted. Furthermore, for areas that do not have stakeholder processes, so long as they publish their studies impacted parties are aware of the role of demand response. 5. The fourth is that the second paragraph seems to be restricting the use of Demand interruption for the sake of Firm Transfer reduction. This can be stated directly without adding the confusion of re-dispatch. By coupling re-dispatch with a constraint of not shedding Demand, the paragraph also creates confusion as to what to do in a situation where the amount of Demand that is allowed to be shed in the first paragraph could be reduced with re-dispatch. Would re-dispatch not be allowed? We suggest that the paragraph be rewritten as follows: "Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management)." 6. The fifth is if the term 'firm demand' survives the proposed changes; is there an intended distinction between the use of the term "firm Demand" and the defined term "Firm Demand"? If these terms are intended to be differently, it is unclear what the term "firm Demand" represents. 7. The final comment is that the last sentence of footnote B is unnecessary and should be deleted. It is

Organization	Yes or No	Question 1 Comment
		never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple NERC standards if it was added here, otherwise it would infer that such actions are acceptable in all other standards. 8. If the first and third sentences must be retained the following wording for the footnote is proposed:b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand, (excluding Interruptible Demand or Demand-Side Management), following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Interruptible Demand or Demand-Side Management o Circumstances where the uses of Demand interruption not directly interrupted by the contingency are documented. Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management).

Response: 1. The SDT believes that the first part of the footnote is necessary to provide context for the items that follow and has crafted the language to provide a balance between flexibility and consistency across NERC. No change made.

2. See ballot response to NPCC #1.

3. See ballot response to NPCC #2.

4. The SDT believes that in situations where an entity's planning studies require the interruption of firm load to remain within BES Facility ratings that the entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be adversely impacted by those decisions have the ability to review and comment on those plans. No change made.

5. See ballot response to NPCC #5.

6. The SDT has corrected the indicated errors.

7. See ballot response to NPCC #6.

8. The SDT has reorganized the text in the footnote to address this concern.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited

Organization	Yes or No	Question 1 Comment
circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~		
Northeast Power Coordinating Council	No	There is concern with the use of the term Demand. It is unclear throughout the footnote whether or not the term Demand includes Interruptible Demand or Demand-Side Management. It is suggested that interruption of Demand be clarified to not include Interruptible Demand or Demand-Side Management to more clearly show the permitted use of Load shedding. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. Language that mitigation of Load and/or Demand interruption should be pursued within the planning process should be reinstated as reinforcement of a Transmission Providers' planning obligations to their load customers, and system operations. Footnote 'b' should be made to read as follows:b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of Load and/or Demand following Contingency events. Interruption of Load and/or Demand is discouraged and all measures to mitigate such interruption should be pursued within the planning process. However, it is recognized that Load and/or Demand will be interrupted if it is directly served by the elements automatically removed from service by the Protection System as a result of a Contingency. Furthermore, in extraordinary circumstances within the planning process Load and/or Demand may need to be interrupted to address BES performance requirements. When interruption of Load and/or Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Circumstances where the use of Load and/or Demand interruption are documented, including alternatives evaluated; and where the Load and/or Demand interruption is made available for review in an open and transparent stakeholder process.If Load and/or Demand interruption is necessary, planning should indicate the amount needed, and not specify how it would be obtained. What Load and/or Demand is

Organization	Yes or No	Question 1 Comment
		interrupted is an operational decision. Additional comments not included in the material listed for footnote ‘b’ on the Comment Form. In the paragraph below the bullets in footnote ‘b’, confusion is introduced through the use of the term “firm Demand”. It is unclear how this is different than the defined term “Firm Demand” and what the implications of the term “firm Demand” are. This footnote should not discourage such adjustments which actually increase the reliability of service to end users. The last sentence of footnote ‘b’ is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own.
Response: This comment is identical to the one made by NPCC in the ballot and the SDT has answered the comment in that forum.		
Arizona Public Service Company	No	It is not clear whether both bullets under "footnote b" have to be met or only one of the two have to be met. It is suggested that the standard be very clear about this.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Southern Company	No	Southern Company is voting "no" on the footnote b ballot because of concerns that the reliability of firm transfers could be compromised. The existing Table I Transmission System Standards, which have been in place as early as the 1997 NERC Planning Standards, do not allow Loss of Demand or Curtailed Firm Transfers under single (Category B) contingencies. Footnote B addressed two areas: 1) the loss of radial or local network load, which Southern Company agrees that the drafting team has appropriately clarified and 2) preparing for the next contingency, which Southern Company does not agree has been appropriately clarified.Southern Company believes the proposed wording "Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch" now allows for the curtailment of firm transfers for single contingencies, whereas Southern Company did not believe this was previously permitted under the standards. Southern Company interprets the new language to allow a planner to curtail firm transfers (generation) to address a single contingency. Southern Company interpreted the original language to not permit the curtailment of firm transfers (generation) for a single contingency, but rather that a planner would develop a suitable transmission reinforcement or other mitigation. Southern Company is concerned that the proposed language could result in a degradation in the dependability of firm transfers impacting the reliability of those customers who rely upon them. Southern Company agrees that a system reconfiguration including the redispatch of generation is appropriate when preparing for a second contingency (Category C).Therfore, a distinction is needed between what is allowed in response to a first contingency and what is allowed to be prepared for a second contingency. The curtailment of firm transfers should not be allowed as a response to the first contingency. This practice would undermine the concept of firm transfers. The curtailment of firm transfers should only be allowed in footnote b as a system adjustment to be prepared for a second contingency. We propose the following to clarify that curtailments are permitted only to prepare

Organization	Yes or No	Question 1 Comment
		for the second contingency. "To prepare for the next contingency, curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch".
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Orlando Utilities Commission	No	The current language provides a balance between the end goal of reliablity (no load loss for B events) and the practical constraint that project cost may outweigh the benefit. Two things are unclear though. Item one: The standard team should clarify if the bullets under note B are intended to be an AND (both conditions met) or an OR (either condition met). As currently written it is not clear. Item #2: The section under firm transfers is in conflict with the section above. If Demand is being curtailed under the first or second bullet and it's served by firm service then service should also be curtailed, however as written any demand served by firm service could not be curtailed.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Duke Energy	Yes	The effective date in the Implementation Plan needs to be changed to match the Effective Date in the standards, in order to clarify the allowed interruption of Non-consequential load before the new Footnote 'b' takes effect.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Hydro-Quebec Transenergie	Yes	Paragraph should be more clear as:b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances within the planning process, Demand may need to be interrupted to address BES performance requirements. In such case : o Only Interruptible Demand or Demand-Side Management are allowed;o Circumstances where the uses of Demand interruption is needed shall be documented, compared to alternatives, and reviewed in an open and transparent stakeholder process that address stakeholder comments. Curtailment of firm transfers is allowed, when coupled with the appropriate and necessary re-dispatch of resources where it can be demonstrated that this does not result in the shedding of any firm Demand and that Facilities remain within applicable Facility Ratings, including Facilities external to the Transmission Planner's planning region when they are relied upon.
Response: The SDT believes that the changes indicated in your proposed footnote do not add any additional clarity. However, the SDT has reorganized the footnote to clarify its intent.		

Organization	Yes or No	Question 1 Comment
b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~		
TVA Trasnmission Plannning & Compliance	No	TVA appreciates the SDT's efforts to clarify and improve this complex and challenging area. However, as mentioned in our last comments regarding footnote b, TVA still believes that the SDT's proposal is still focusing more on reliability of local loads than on the overall reliability of the BES. Reliability of local loads should be addressed outside the TPL standards and therefore should not be used/referenced in footnote b. Existing stakeholder processes (referred to in the SDT proposal) typically focus on larger system issues and not on local load serving. TVA believes that some local load should be allowed to be dropped in order to maintain BES reliability. Instead of the proposed footnote b, TVA suggests that the SDT define a "local area" with guidelines detailing the reliability requirements for these local area loads. This would separate the local area load requirements from the BES requirements in the TPL standards.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
New Brunswick System Operator	No	NBSO agrees with the principles of the current version of the proposed footnote, as far as NBSO's interpretation of the footnote is correct. NBSO has the following detailed comments:1. The first paragraph contains many general statements that attempts to capture essential planning principles. NBSO feels that such language is not suited for a footnote. NBSO suggests re-wording of the first paragraph to state:Interruption of Demand may be utilized within the planning process to address BES performance requirements. Such cases are limited to:NBSO also suggests turning the phrase that addresses Demand lost that was served by elements removed from service as a result of a Contingency into a bullet item. NBSO feels

Organization	Yes or No	Question 1 Comment
		that this adds clarity since all of the acceptable instances of Demand interruption are now listed as bulleted items.2. NBSO interprets that the currently proposed footnote allows for the two bulleted options to be used exclusively or in combination. Thus for clarification NBSO suggests adding “or” after each bulleted item, with the exclusion of the final bulleted item.3. NBSO suggests removing the last sentence of the last paragraph. Likely all industry members understand that causing reliability concerns in other areas is never acceptable. This principle is not limited to the standard in question, and thus such a statement could require the update of other standards.4. NBSO interprets that the use of the word “Demand” in the second bullet of the proposed footnote is referring to use of Firm Demand since the first bullet covers the other types of Demand (Demand = Firm Demand + Interruptible Demand). As such NBSO suggests replacing “Demand” with “Firm Demand” in the second bullet.5. NBSO feels that the statement “that includes addressing stakeholder comments” should be removed from the last phrase of the second bullet. An open and transparent stakeholder process should adequately address stakeholder comments and concerns. Explicitly specifying that all stakeholder comments be addressed may add undue burden if the word “address” is misconstrued. The task of addressing stakeholder comments is more appropriately addressed and defined in each area’s respective process.6. NBSO suggests replacing the word “shedding” with “interruption” in the last phrase of the last paragraph to remain consistent with the rest of the proposed footnote. NBSO also suggests capitalizing “firm” in the term “Firm Demand” to remain consistent with the NERC glossary of terms.7. There is no term “transfers” in the NERC glossary of terms. Perhaps some other defined term from the glossary could be used in lieu of “transfers” (e.g. Firm Transmission Service).Taking into account the NBSO comments, the footnote could read as follows:b) Interruption of Demand may be utilized within the planning process to address BES performance requirements. Such cases are limited to:-Demand directly served by Elements removed from service as a result of a Contingency, or-Use of Interruptible Demand or Demand-Side Management, or-Interruption of Firm Demand when acceptable circumstances for such interruptions are documented (including alternatives evaluated), and where the Firm Demand interruption is subject to review in an open and transparent stakeholder process.Curtailment of Firm Transmission Service is allowed when coupled with the appropriate re-dispatch of resources obligated to do so, and it can be demonstrated that Facilities remain within applicable Facility Ratings and there is no additional interruption of Firm Demand.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Manitoba Hydro	No	The last bullet should be made clearer by adding the words “in jurisdictions” before the word “where”. Not all jurisdictions are mandated to have a stakeholder process, so the standard should be clearly written to recognize this situation. "Circumstances where the use of Demand interruption are documented, including alternatives evaluated; and IN JURISDICTIONS where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments."

Organization	Yes or No	Question 1 Comment
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Ameren	No	We agree with the statement that an objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following single contingency events. While we appreciate the drafting team's efforts in removing the need for acceptance by other parties in the stakeholder process, we still feel that language in the second bullet of the revised footnote b should be modified to remove all references to an open and transparent stakeholder process. Existing RTO stakeholder processes that we are aware of focus on larger system issues, rather than on local load serving issues. Therefore, we believe that the load serving issues following single contingency events are issues between the customer and the utility, and should be addressed in one-on-one forums between those entities.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
National Grid	No	National Grid supports the direction the drafting team has taken. However, it has a few concerns with the language of the footnote as amended. 1. Use of the term "Demand": In the first sentence, it is unclear whether the term Demand includes Interruptible Demand and Demand-Side Management. It is suggested that interruption of Demand be clarified to exclude Interruptible Demand or Demand-Side Management. 2. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. 3. National Grid also suggests changing "Demand interruption" to "interruption of Demand" in second bullet under "b)" to avoid awkward and incorrect phasing.4. 'Addressing stakeholder comments' introduces undefined actions which may be required in response to the comments. If 'Demand interruption is subject to review in an open and transparent stakeholder process', then stakeholder comments will be addressed without creating an undefined commitment to require it. As a result, "that includes addressing stakeholder comments" should be deleted. 5. The second paragraph seems to be restricting the use of Demand interruption for the sake of Firm Transfer reduction. This can be stated directly without adding the confusion of re-dispatch. By coupling re-dispatch with a constraint of not shedding Demand, the paragraph also creates confusion as to what to do in a situation where the amount of Demand that is allowed to be shed in the first paragraph could be reduced with re-dispatch. Would re-dispatch not be allowed? National Grid suggests that the paragraph be rewritten as follows: 'Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management).' 6. National Grid seeks clarification if there is an intended distinction between the use of the term "firm Demand" and the defined term "Firm Demand" or is that just a typo?7. The last sentence of footnote B is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple

Organization	Yes or No	Question 1 Comment
		NERC standards if it were added here, otherwise it would infer that such actions are acceptable in all other standards.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Northeast Utilities	No	The revised language of Footnote b suggests that non-consequential demand interruption (load that is not directly served by the elements removed from service as a result of the contingency) could be used to mitigate reliability concerns arising from NERC Category B contingency events (i.e., single element contingencies). This language seems to encourage operational workarounds and adds burdens for operators of the system. NU believes this is not consistent with planning a highly reliable bulk electric system and thus does not support this weaker language.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Kansas City Power & Light	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
PacifiCorp	Yes	appreciates the efforts of the SDT and supports revision of TLP-002-0 Table 1 footnote “b” as stated in this draft.
Transmission Strategies, LLC	Yes	
Mohave Electric Cooperative	Yes	
Pepco Holding Inc	Yes	
American Electric Power	Yes	
Georgia Transmission Corporation	Yes	
American Transmission Company	Yes	

Organization	Yes or No	Question 1 Comment
Midwest ISO	Yes	
Independent Electricity System Operator	Yes	
Response: Thank you for your support.		

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Successive Ballot — Project 2010-11 – TPL Table 1, Footnote b

Successive Ballot Dates: 12/27/2010 - 1/5/2011

Summary Consideration:

The SDT reviewed all of the comments received and has made a clarifying change to the structure of the footnote to address industry concerns as to the intent of the SDT. No contextual changes have been made to the footnote. Therefore, the SDT is recommending that this project be moved to a recirculation ballot.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

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

Balloter	Company	Seg-ment	Vote	Comment
Richard J. Mandes	Alabama Power Company	3	Negative	Southern Company is voting "no" on the footnote b ballot because of concerns that the reliability of firm transfers could be compromised. The existing Table I Transmission System Standards,

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Balloter	Company	Seg-ment	Vote	Comment
Anthony L Wilson	Georgia Power Company	3	Negative	which have been in place as early as the 1997 NERC Planning Standards, do not allow Loss of Demand or Curtailed Firm Transfers under single (Category B) contingencies. Footnote B addressed two areas: 1) the loss of radial or local network load, which Southern Company agrees that the drafting team has appropriately clarified and 2) preparing for the next contingency, which Southern Company does not agree has been appropriately clarified. Southern Company believes the proposed wording "Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch" now allows for the curtailment of firm transfers for single contingencies, whereas Southern Company did not believe this was previously permitted under the standards. Southern Company interprets the new language to allow a planner to curtail firm transfers (generation) to address a single contingency. Southern Company interpreted the original language to not permit the curtailment of firm transfers (generation) for a single contingency, but rather that a planner would develop a suitable transmission reinforcement or other mitigation. Southern Company is concerned that the proposed language could result in a degradation in the dependability of firm transfers impacting the reliability of those customers who rely upon them. Southern Company agrees that a system reconfiguration including the redispatch of generation is appropriate when preparing for a second contingency (Category C). Therfore, a distinction is needed between what is allowed in response to a first contingency and what is allowed to be prepared for a second contingency. The curtailment of firm transfers should not be allowed as a response to the first contingency. This practice would undermine the concept of firm transfers. The curtailment of firm transfers should only be allowed in footnote b as a system adjustment to be prepared for a second contingency. We propose the following to clarify that curtailments are permitted only to prepare for the second contingency. "To prepare for the next contingency, curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch".
Don Horsley	Mississippi Power	3	Negative	
Horace Stephen Williamson	Southern Company Services, Inc.	1	Negative	

Response: The SDT has changed the wording 'coupled with' to 'achieved through' to better clarify the SDT's intent.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand

Balloter	Company	Seg-ment	Vote	Comment
interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~ As drafted, footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. It further clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the footnote. No change made.				
Jennifer Richardson	Ameren Energy Marketing Co.	6	Negative	We agree with the statement that an objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following single contingency events. While we appreciate the drafting team's efforts in removing the need for acceptance by other parties in the stakeholder process, we still feel that language in the second bullet of the revised footnote b should be modified to remove all references to an open and transparent stakeholder process. Existing RTO stakeholder processes that we are aware of focus on larger system issues, rather than on local load serving issues. Therefore, we believe that the load serving issues following single contingency events are issues between the customer and the utility, and should be addressed in one-on-one forums between those entities.
Kirit S. Shah	Ameren Services	1	Negative	
Response: The SDT disagrees that this should be handled through two party interactions. The SDT believes that in situations where an entity's planning studies require the interruption of Firm Demand to remain within BES Facility Ratings that the entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be impacted by those decisions have the ability to review those plans. No change made.				
Steven Norris	APS	3	Negative	It is not clear whether both bullets under "footnote b" have to be met or only one of the two have to be met. It is suggested that the standard be very clear about this
Mel Jensen	APS	5	Negative	
Robert D Smith	Arizona Public Service Co.	1	Negative	
Response: The bullets – o Interruptible Demand or Demand-Side Management and o Circumstances where … are not requirements that must be met, but rather they define the conditions, either one or both, where Load is allowed to be interrupted. The SDT has rearranged the footnote to clarify the intent of the footnote. **b)** An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch,				

Balloter	Company	Seg-ment	Vote	Comment
				where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~ ~~-C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~
John Tolo	Tucson Electric Power Co.	1	Negative	The first sentence of the second paragraph appears to conflict with the first paragraph in that it indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.
Scott Kinney	Avista Corp.	1	Affirmative	The first sentence of the second paragraph appears to conflict with the first paragraph in that it indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.
Robert Lafferty	Avista Corp.	3	Affirmative	
Brenda S. Anderson	Bonneville Power Administration	6	Affirmative	Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.
William Mitchell Chamberlain	California Energy Commission	9	Affirmative	I am voting for this improved standard but I am concerned that the first sentence of the second paragraph appears to conflict with the first paragraph in that it indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. This problem could be corrected by adding language to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.

Balloter	Company	Seg-ment	Vote	Comment
Chang G Choi	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	1	Affirmative	Tacoma Power agrees that the revision is better than the existing language. However, to improve clarity on the interrelationship of the 2 paragraphs of Footnote B, we strongly suggest adding the following phrase to the end of the first sentence of the second paragraph, "unless the firm Demand is allowed to be shed pursuant to the above paragraph in this footnote."
Max Emrick	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	5	Affirmative	
James Tucker	Deseret Power	1	Affirmative	As drafted the first paragraph of proposed Footnote B identifies the objective of minimizing interruption of Demand following Contingencies and goes on to identify the limited situation where interruption of demand may be necessary. However, the first sentence of the second paragraph appears to conflict with the first paragraph in that it indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed
Chifong L. Thomas	Pacific Gas and Electric Company	1	Affirmative	PG&E supports the proposed footnote B. We believe, however, there is a potential for confusion with the language as currently drafted. As drafted the first paragraph of proposed Footnote B identifies the limited situations where interruption of demand may be necessary and would be allowed. However, the first sentence of the second paragraph indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. Taken together with the first paragraph, this requirement can be confusing because the first paragraph potentially conflicts with the second paragraph. Please change the first sentence in the second paragraph to read, "Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand, the interruption of which is otherwise allowed as described above."
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Affirmative	Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.
Travis Metcalfe	Tacoma Public Utilities	3	Affirmative	Tacoma Power agrees that the revision is better than the existing language. However, to improve clarity on the interrelationship of the 2 paragraphs of Footnote B, we strongly suggest adding the following phrase to the end of the first sentence of the second paragraph, "unless the firm Demand is allowed to be shed pursuant to the above paragraph in this footnote."

Balloter	Company	Seg-ment	Vote	Comment
Keith Morisette	Tacoma Public Utilities	4	Affirmative	
Michael C Hill	Tacoma Public Utilities	6	Affirmative	
Beth Young	Tampa Electric Co.	1	Affirmative	Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed
Ronald L Donahey	Tampa Electric Co.	3	Affirmative	
RJames Rocha	Tampa Electric Co.	5	Affirmative	Recommend adding language to paragraph 2, sentence 1 to clarify shedding of firm demand is allowed as stated in Paragraph 1.
Benjamin F Smith II	Tampa Electric Co.	6	Affirmative	
Melissa Kurtz	U.S. Army Corps of Engineers	5	Affirmative	Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.
Brandy A Dunn	Western Area Power Administration	1	Affirmative	As drafted, the first paragraph of proposed Footnote B identifies the objective of minimizing interruption of Demand following Contingencies and goes on to identify the limited situation where interruption of demand may be necessary. However, the first sentence of the second paragraph appears to conflict with the first paragraph in that it indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. Western recommends that the Drafting Team include language at the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.

Balloter	Company	Seg-ment	Vote	Comment
Louise McCarren	Western Electricity Coordinating Council	10	Affirmative	WECC supports the concept that is clarified in the proposed language for Footnote B. We have noted however, what could potentially be confusing language between paragraphs one and two of the proposed language. Paragraph one correctly indicates that one of the objectives of transmission planning is to minimize the likelihood and magnitude of interruption of Demand. The first paragraph also recognizes that while this is an objective, there may be certain limited conditions where Demand is interrupted. In recognizing this, the first paragraph lists those limited instances when Demand may be interrupted. However, the first sentence of paragraph two could be interpreted to mean that shedding of Firm Demand is not allowed. The sentence means that shedding of Firm Demand is not allowed due to curtailment of firm transfers, but if there is a situation where curtailment of firm transfers is necessary and curtailment of Demand per the reasons listed in the first paragraph occurs, it should be clear that this is allowed. Suggest adding the following language, or something similar, to the end of the first sentence of the second paragraph of Footnote B. ...except as allowed above.

Response: The SDT has reorganized the footnote to clarify intent and address the issue raised.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

Balloter	Company	Seg-ment	Vote	Comment
Venkataramakrishnan Vinnakota	BC Hydro	2	Negative	Footnote "b" of TPL-001/2/3/4 is still vague and not acceptable. The last paragraph of Footnote b now reads: "Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected." We would like the SDT to answer the following questions related to the paragraph quoted above: 1) What is meant by "firm transfers"? Is it simply energy flowing in real-time on Firm Transmission Service (NERC defined term) that was not previously curtailed in the hour-ahead or day-ahead scheduling processes, or does it refer to ALL Firm Transmission Service that was sold on a path? 2) Please provide an example of what an "appropriate re-dispatch of resources obligated to re-dispatch" could look like? 3) Assuming an outage of a single transmission line (N-1 Category B event) has occurred and assuming that no "resources [are] obligated to redispatch" for this outage, would a transmission provider be allowed to curtail Firm Transmission Service that it has sold in order to prepare to withstand the next worst credible contingency? 4) Would transmission providers be allowed to sell Firm Transmission Service on a path above what could be delivered with any one element of that path out of service across a range of operating conditions? 5) If the proposed Footnote b is approved, and assuming an appropriate obligation to redispatch could not be negotiated, would utilities have to reinforce their system (within 60 months) to ensure that Firm Transmission Services already sold on particular paths would not be curtailed when any one element of that path is out of service? 6) If a transmission provider employs Generation Dropping for single contingencies in order to support Firm Transmission Service between regions, and assuming there are no provisions for obligated re-dispatch, would the proposed Footnote b force a recalculation of firm vs non-firm transfer capability? 7) Path 66 (PACI) and Path 65 (PDCI) can both see significant derates in their firm transfer capability for single contingencies. How would the proposed Footnote b impact Firm Transmission on these paths? Further, the Project 2010-11 SDT (Footnote "b") should be amalgamated with the Project No. 2006-02 SDT (TPL-001 through TPL004 amalgamation/update): 1. It doesn't make any sense to update Footnote "b" of TPL-001 based on the existing approved

<table>
<tr><th>Balloter</th><th>Company</th><th>Seg-ment</th><th>Vote</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td></td><td>version of TPL-001 when the language in that standard is being revised and terms that Footnote “b” makes reference to will be changed. Draft #6 (2010-Oct-19) of TPL-001 has changed “Footnote b” to “Footnote 9”.

2. Draft #6 of TPL-001 has changed the column heading relevant to “Footnote b” from “Loss of Demand or Curtailed Firm Transfers” to “Interruption of Firm Transmission Service Allowed”.

3. Draft #6 of TPL-001 has seven new definitions including the following two definitions that would be expected to be relevant to Footnote b: 3.1. Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault. 3.2. Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

4. The Project 2006-02 SDT has placed Draft #6 of TPL-001 on hold, stating, “The team will delay moving the standard forward until the resolution of “footnote b” has become clear.”</td></tr>
<tr><td colspan="5">Response: 1. For consistency with the existing standard text, the term ‘firm transfer’ is retained. Therefore, the interpretation of “firm transfers” remains unchanged.
2. One example would be a contractual arrangement that defines clear expectations to alternately serve Load upon the removal of the firm transfer so that no loss of Load occurs.
3. In the planning timeframe, footnote ‘b’ addresses single Contingencies (Cat. B) and footnote ‘c’ addresses the Cat. C Contingencies. Neither footnote prohibits System adjustments, which could include re-dispatch of your own resources to prepare for the next Contingency.
4. How Firm Transmission Service (FTS) is sold is addressed in individual tariffs in concert with the MOD standards.
5. The implementation plan provides 60 months after regulatory approval for entities to comply with the modified standard. How that is accomplished is up to individual entities.
6. & 7 Each circumstance may need to be evaluated individually and additional documentation of understandings may be necessary.
7-1 - 4. Based on ballot comments and regulatory orders, the SDT determined that the best course of action was to address footnote ‘b’ as a standalone item and then incorporate the changes approved for footnote ‘b’ into the new TPL-001-2 in a manner consistent with the other proposed changes in TPL-001-2.</td></tr>
<tr><td>Christopher L de Graffenried</td><td>Consolidated Edison Co. of New York</td><td>1</td><td>Negative</td><td rowspan="2">Interruptible Demand, like Demand-Side-Management, is an operational tool. We do not believe it appropriate to use operational tools for transmission planning. A load serving entity should not claim to serve loads it plans to disconnect during a design contingency. In other words, these loads should be excluded from the load forecast in the first place and, thereby, would not be represented in power flows that are utilized to assess system performance under the TPL standards. This approach prevents the use of such load interruptions to address any deficiency found in TPL-type</td></tr>
<tr><td>Peter T Yost</td><td>Consolidated Edison Co. of New York</td><td>3</td><td>Negative</td></tr>
</table>

Balloter	Company	Seg-ment	Vote	Comment
Wilket (Jack) Ng	Consolidated Edison Co. of New York	5	Negative	assessments.
Nickesha P Carrol	Consolidated Edison Co. of New York	6	Negative	
Response: Entities across the continent have many different Interruptible and Demand-Side Management programs that have many different attributes and rules. Some entities have Interruptible Demand programs that are appropriate for planning purposes.				
Chuck B Manning	Electric Reliability Council of Texas, Inc.	2	Negative	The introductory paragraph of footnote b includes policy language. Since this is a reliability standard-and not a policy directive-the general narrative setting forth the desired policy goal of minimizing load-shedding is misplaced. Including policy language can cloud the specific issues the standard attempts to address, and ERCOT recommends deleting the first two sentences in the introductory paragraph. The next sentence in the introductory paragraph goes on to state, generally, that demand may be interrupted to "address BES performance requirements.” This phrase is vague. To which performance requirements does this refer? The intent is not clear. If the intent is to generally recognize the need to shed load to respect to NERC standards and to allow flexibility for an entity to exercise discretion relative to meeting BES performance requirements, then that intent should be clearly reflected in the language. Furthermore, the last sentence of the introductory paragraph and the subsequent bullet points are arguably inconsistent with this approach, because they could be viewed as removing an entity’s flexibility/discretion by limiting the circumstances when load can be shed. The second bullet point is unnecessary, because it is already apparent that interruptible demand/demand side management programs can be used according to their terms. This could create confusion in that it could be implied that, absent the need to use these to meet BES performance requirements, using them otherwise is inconsistent with/not allowed under footnote b. Simply put, those products are not load shedding as contemplated by this footnote. Therefore they should not be listed here. With respect to the third bullet point, the phrase "demand that does not adversely impact overall BES reliability" is not adequately defined, and provides opportunity for confusion. This is an ambiguous phrase and can’t be linked back to objective NERC standards/requirements. The bullet points should avoid ambiguity to mitigate ambiguity risk in audits.

Balloter	Company	Seg-ment	Vote	Comment
				In addition, the last part of the language in this bullet imposing an open and transparent stakeholder process is unclear. What is the intent behind requiring review in a stakeholder process? If it is to establish the ability of the entity to develop load shedding procedures beyond those explicitly contemplated in footnote b, ERCOT questions if it is reasonable for the responsible entity to be required to get “permission” from stakeholders to implement reliability measures related to its obligation as the functional entity. Again, the language simply is not clear. Accordingly, ERCOT recommends this bullet point be removed. If it is retained, it should be revised consistent with these comments to remove ambiguous language to mitigate potential confusion around the meaning/scope of the footnote in the administration of the CMEP. In addition, ERCOT recommends revising the draft footnote b to allow for planned Demand interruption as a means of mitigation during interim periods when a unanticipated (such as unexpected demand growth or unit retirements) or temporary change on the system occurs in a timeframe that is shorter than the time necessary to plan and implement the system upgrades necessary to avoid the Demand interruption. Finally, in the last paragraph of footnote b, it isn’t clear why “Transmission Service” was changed to “transfers.” Firm transmission service is a service provided in some regions, and it provides relative value to other types of services-e.g., non-firm and network. The mention of transmission service may also be irrelevant in this footnote, since the allowance of its interruption doesn't also allow for load shedding. Therefore, ERCOT recommends eliminating the last paragraph of footnote b.

Response: The SDT believes that the first part of the footnote is necessary to provide context for the items that follow and has crafted the language to provide a balance between flexibility and consistency across NERC. No change made.

The term “BES performance requirements” references the other requirements within the TPL standard and the SDT has removed the phrase “demand that does not adversely impact overall BES reliability”.

In a previous posting, entities had stated that it was not clear that the use of Interruptible Load and Demand Side Management was permitted. The SDT added this section to address those concerns. The SDT has reorganized and reformatted the footnote to improve clarity.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner’s planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm

Balloter	Company	Seg-ment	Vote	Comment
Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~ The open and transparent process does not require "permission", but rather it facilitates the open sharing of information between entities that have responsibility for ensuring BES reliability. The SDT decided to not limit the use of the footnote to a specific time period because there are circumstances where the longer term use may be implemented without adversely impacting BES reliability. For consistency with the existing standard text, the term 'firm transfer' is retained. No change made.				
Claudiu Cadar	GDS Associates, Inc.	1	Negative	We appreciate all the work conducted by SDT to adjust current footnote "b" however, we disagree with the current approach mainly from the same reasons iterated during last comment period, as follows: • The definition does not go far enough with recognition that interruption of Demand should be mitigated if at all possible. The language should encourage the TP to develop mitigation plans that could be implemented as an alternative to Demand interruption. • Use of Interruptible Demand should only be implemented if the Transmission Planner can point to a contract between the Transmission Provider and Transmission Customer that permits load curtailment. • Under FERC Order 890, Conditional Firm transmission service can be granted for entities who voluntarily acknowledge the right of the Transmission Provider to curtail their transaction or provide re-dispatch. This should be the only transfer which can be utilized in the Planning Horizon for interruption of Demand for Note b. We suggest using the following wording as emphasized below: "An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events and to develop mitigation plans that do not call for the curtailment of Demand.

Balloter	Company	Seg-ment	Vote	Comment
				It is recognized that Demand will be interrupted if it is directly served by the elements removed from service as a result of the Contingency and in very limited circumstances when approaching intermediate solutions to restore BES reliability. When interruption of Demand is utilized within the planning process, such interruption is limited to: ? Demand that is directly served by the elements that are removed from service as a result of the Contingency, ? Interruptible Demand or Demand-Side Management, where the Customer has given explicit rights to the Transmission Provider for curtailment of their Demand, ? Demand, other than Interruptible Demand or Demand-Side Management, that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand are documented, including alternatives evaluated; where the Load-Serving Entity who has responsibility for serving such Demand has agreed to the curtailment, and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of Firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch per the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected. In addition, any Conditional Firm transfers may be curtailed, in accordance with the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider."
Response: In the footnote, the SDT has acknowledged that interrupting Firm Demand is not the preferred solution to BES concerns, while recognizing that this may not always be possible. The SDT believes that the footnote as drafted strikes an appropriate balance. No change made. It is well understood that there must be some agreement or contract before interruptible Demand or Demand-Side Management can be utilized by the planner. The SDT disagrees that there should be a prohibition on utilizing other resources obligated to re-dispatch for Contingencies, unless it has been characterized as "conditional firm". Entities should not be restricted from utilizing other dispatch scenarios, as long as Firm Demand is not interrupted. For the reasons stated above, the SDT has not modified the footnote as suggested.				
Joe D Petaski	Manitoba Hydro	1	Negative	The last bullet should be made clearer by adding the words "in jurisdictions" before the word "where". Not all jurisdictions are mandated to have a stakeholder process, so the standard should be clearly written to recognize this situation. "Circumstances where the use of Demand interruption are documented, including alternatives evaluated; and IN JURISDICTIONS where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments."
Greg C. Parent	Manitoba Hydro	3	Negative	
S N Fernando	Manitoba Hydro	5	Negative	
Daniel	Manitoba Hydro	6	Negative	

Balloter	Company	Seg-ment	Vote	Comment
Prowse				
Response: The SDT believes that if Firm Demand is planned to be interrupted utilizing footnote 'b', there must be an open and transparent stakeholder process to ensure that all parties that may be impacted have been notified and have an opportunity to provide comments. No change made.				
Spencer Tacke	Modesto Irrigation District	4	Negative	I am voting NO on the proposed revision because the second bullet of the proposed revision is nebulous as to how the exemption process will occur, and how it will be monitored by the auditors. Also, the last sentence of the last paragraph of the proposed change is nebulous about keeping facility flows within applicable Normal and Emergency thermal ratings. Thank you.
Response: Rather than mandate a one-size-fits-all process, the SDT has provided entities the latitude to utilize existing processes, modify existing processes, or create new processes to provide an open and transparent stakeholder process. The SDT cannot comment on future actions of the auditors. The SDT disagrees that maintaining Facilities within applicable Facility Ratings is a nebulous concept. That part of the footnote was included to ensure that the plans to resolve a situation on a planner's System did not create other overloads. No change made.				
Saurabh Saksena	National Grid	1	Negative	National Grid supports the direction the drafting team has taken. However, it has a few concerns with the language of the footnote as amended. 1. Use of the term "Demand": In the first sentence, it is unclear whether the term Demand includes Interruptible Demand and Demand-Side Management. It is suggested that interruption of Demand be clarified to exclude Interruptible Demand or Demand-Side Management. 2. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet.

Balloter	Company	Seg-ment	Vote	Comment
Michael Schiavone	Niagara Mohawk (National Grid Company)	3	Negative	3. National Grid also suggests changing "Demand interruption" to "interruption of Demand" in second bullet under "b)" to avoid awkward and incorrect phasing. 4. 'Addressing stakeholder comments' introduces undefined actions which may be required in response to the comments. If 'Demand interruption is subject to review in an open and transparent stakeholder process', then stakeholder comments will be addressed without creating an undefined commitment to require it. As a result, "that includes addressing stakeholder comments" should be deleted. 5. The second paragraph seems to be restricting the use of Demand interruption for the sake of Firm Transfer reduction. This can be stated directly without adding the confusion of re-dispatch. By coupling re-dispatch with a constraint of not shedding Demand, the paragraph also creates confusion as to what to do in a situation where the amount of Demand that is allowed to be shed in the first paragraph could be reduced with re-dispatch. Would re-dispatch not be allowed? National Grid suggests that the paragraph be rewritten as follows: 'Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management).' 6. National Grid seeks clarification if there is an intended distinction between the use of the term "firm Demand" and the defined term "Firm Demand" or is that just a typo? 7. The last sentence of footnote B is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple NERC standards if it were added here, otherwise it would infer that such actions are acceptable in all other standards.

Response: 1. The SDT has reorganized the text in the footnote to address this concern.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

Balloter	Company	Seg-ment	Vote	Comment
~~Interruptible Demand or Demand-Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~ **2.** The SDT has reorganized the text in the footnote to address this concern. **3.** The SDT believes that the proposed change does not add additional clarity to the footnote. No change made. **4.** The SDT disagrees that each review process automatically will have a response to comments element. Therefore, the SDT added that element to ensure that all stakeholder processes will include that element. No change made. **5.** The SDT has reorganized the text in the footnote to address this concern. **6.** The SDT has corrected the capitalization errors. **7.** Since the planned action of curtailing of firm transfers may adversely impact neighboring systems, the SDT believes that it is important in this situation to articulate a condition that is normally implied. The SDT disagrees that an explicit statement in this footnote changes the intent of all other standards. No change made.				
Tony Eddleman	Nebraska Public Power District	3	Negative	NPPD votes NO due to the ambiguity of the terms "Curtailment of firm transfers is allowed, when coupled the appropriate re-dispatch of resources" with respect to a Category B contingency event. NPPD does not support the curtailment of firm transfers or re-dispatch to meet the performance requirements during a Category B (N-1) event. Curtailment of firm transfers and re-dispatch are allowable following acceptable performance for the Category B (N-1) event, to get ready for the next Category C type of event.
Don Schmit	Nebraska Public Power District	5	Negative	
Response: As drafted, footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. It further clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. No change made.				

Balloter	Company	Seg-ment	Vote	Comment
Randy MacDonald	New Brunswick Power Transmission Corporation	1	Negative	In general: NERC standards should not dictate circumstances or acceptable transmission contingencies under which the tripping of customers loads is acceptable. That should be an issue between the utility of supply, the customer, and the local regulating body so long as the interruption to customers (for whatever contingency) is controlled and does not cause problems on the BES, or to neighboring utilities. Specifically, 1. The second bullet: The last sentence (following the semicolon) should be removed. The local regulating body should provide input or approval. 2. NB Power Transmission interprets that the currently proposed footnote allows for the two bulleted options to be used exclusively or in combination. Thus for clarification suggest adding “or” after the first bulleted item.

Response: The SDT disagrees that this should be handled exclusively with the local regulating body. The SDT believes that in situations where an entity’s planning studies require the interruption of Firm Demand to remain within BES Facility Ratings that the entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be adversely impacted by those decisions have the ability to review those plans**.** No change made.

The SDT has reorganized the footnote to clarify its intent and address the issue raised.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner’s planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected.~~

Balloter	Company	Seg-ment	Vote	Comment
Alden Briggs	New Brunswick System Operator	2	Negative	NBSO agrees with the principles of the current version of the proposed footnote assuming NBSO's interpretation of the footnote is correct. NBSO has the following detailed comments: 1. The first paragraph contains many general statements that attempts to capture essential planning principles. NBSO feels that such language is not suited for a footnote. NBSO suggests re-wording of the first paragraph to state: Interruption of Demand may be utilized within the planning process to address BES performance requirements. Such cases are limited to: NBSO also suggests turning the phrase that addresses Demand lost that was served by elements removed from service as a result of a Contingency into a bullet item. NBSO feels that this adds clarity since all of the acceptable instances of Demand interruption are now listed as bulleted items. 2. NBSO interprets that the currently proposed footnote allows for the two bulleted options to be used exclusively or in combination. Thus for clarification NBSO suggests adding "or" after each bulleted item, with the exclusion of the final bulleted item. 3. NBSO suggests removing the last sentence of the last paragraph. Likely all industry members understand that causing reliability concerns in other areas is never acceptable. This principle is not limited to the standard in question, and thus such a statement could require the update of other standards. 4. NBSO interprets that the use of the word "Demand" in the second bullet of the proposed footnote is referring to use of Firm Demand since the first bullet covers the other types of Demand (Demand = Firm Demand + Interruptible Demand). As such NBSO suggests replacing "Demand" with "Firm Demand" in the second bullet. 5. NBSO feels that the statement "that includes addressing stakeholder comments" should be removed from the last phrase of the second bullet. An open and transparent stakeholder process should adequately address stakeholder comments and concerns. Explicitly specifying that all stakeholder comments be addressed may add undue burden if the word "address" is misconstrued. The task of addressing stakeholder comments is more appropriately addressed and defined in each area's respective process. 6. NBSO suggests replacing the word "shedding" with "interruption" in the last phrase of the last paragraph to remain consistent with the rest of the proposed footnote. NBSO also suggests capitalizing "firm" in the term "Firm Demand" to remain consistent with the NERC glossary of terms.

Balloter	Company	Seg-ment	Vote	Comment
				7. There is no term "transfers" in the NERC glossary of terms. Perhaps some other defined term from the glossary could be used in lieu of "transfers" (e.g. Firm Transmission Service). Taking into account the NBSO comments, the footnote could read as follows: b) Interruption of Demand may be utilized within the planning process to address BES performance requirements. Such cases are limited to: -Demand directly served by Elements removed from service as a result of a Contingency, or -Use of Interruptible Demand or Demand-Side Management, or -Interruption of Firm Demand when acceptable circumstances for such interruptions are documented (including alternatives evaluated), and where the Firm Demand interruption is subject to review in an open and transparent stakeholder process. Curtailment of Firm Transmission Service is allowed when coupled with the appropriate re-dispatch of resources obligated to do so, and it can be demonstrated that Facilities remain within applicable Facility Ratings and there is no additional interruption of Firm Demand.

Response: 1 & 2. The SDT believes that the first part of the footnote is necessary to provide context for the items that follow and has crafted the language to provide a balance between flexibility and consistency across NERC. The SDT has reorganized the footnote to clarify its intent and address the issue raised.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

3. Since the planned action of curtailing of firm transfers may adversely impact neighboring Systems, the SDT believes that it is important in this situation to articulate a condition that is normally implied. The SDT disagrees that an explicit statement in this footnote changes the intent of all other standards.
4. The SDT has reorganized the footnote to clarify its intent and address the issue raised.
5. The SDT believes that in situations where an entity's planning studies require the interruption of Firm Demand to remain within BES Facility Ratings that the

Balloter	Company	Seg- ment	Vote	Comment
entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be adversely impacted by those decisions have the ability to review those plans. No change made. **6.** The SDT does not believe that replacing the term shedding with interruption adds clarity and did not make the proposed change. The SDT has reorganized the footnote to clarify its intent and address the second issue. **7.** For consistency with the existing standard text, the term 'firm transfer' is retained. No change made.				
David H. Boguslawski	Northeast Utilities	1	Negative	The revised language of Footnote b suggests that non-consequential demand interruption (load that is not directly served by the elements removed from service as a result of the contingency) could be used to mitigate reliability concerns arising from NERC Category B contingency events (i.e., single element contingencies). This language seems to encourage operational workarounds and adds burdens for operators of the system. NU believes this is not consistent with planning a highly reliable bulk electric system and thus does not support this weaker language.
Response: The SDT believes that the language in this footnote is not weaker and does not encourage operational workarounds. The footnote language provides the framework necessary to ensure that in situations where an entity's planning studies require the interruption of Firm Demand to remain within BES Facility Ratings that the entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be adversely impacted by those decisions have the ability to review those plans. No change made.				
Brad Chase	Orlando Utilities Commission	1	Negative	"Two Items prevent us from voting yes. Item #1: The standard team should clarify if the bullets under note B are intended to be an AND (both conditions met) or an OR (either condition met). As currently written it is not clear. Item #2: The section under firm transfers is in conflict with the section above. If Demand is being curtailed under the first or second bullet and it's served by firm service then service should also be curtailed, however as written any demand served by firm service could not be curtailed. Other then these items the revisions does an excellent job of addressing the issue of load shedding under first contingency conditions and practical reliablity."
Ballard Keith Mutters	Orlando Utilities Commission	3	Negative	
Response: The SDT has reorganized the footnote to clarify its intent and address this issue. b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~				

Balloter	Company	Seg-ment	Vote	Comment
~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~				
Linda Brown	San Diego Gas & Electric	1	Negative	Footnote b is a group of exceptions to the requirements for Category B contingencies. To add clarity to the footnote, SDG&E would prefer that each exception be listed separately within the footnote. As SDG&E understands the footnote, the following exceptions can occur after the loss of a single element, • Interruptible Demand can be used to unload a circuit, but the circuit(s) must remain below emergency rating(s) at all times. • Demand-Side Management can be used to unload a circuit, but the circuit(s) must remain below emergency rating(s) at all times. • Demand served by a radial element which is faulted may be interrupted. • Curtailment of firm transfers is allowed, when coupled with re-dispatch of resources obligated to re-dispatch. SDG&E votes against the proposed language for the following reasons: SDG&E feels system reliability alone should drive the need for a technical standard and the language of the standard should reflect the need without reference to the process. FERC Order 890 set the forum for the stakeholder process which provides commercial incentives and a level playing field for any participant to build a transmission project. When considering compliance to the standards, reference to "stakeholder process" is inappropriate and should be removed. Section 4 of the TPL standards assigns responsibility for meeting the standards to the Planning Authority and the Transmission Planner. These entities are subject to penalties if the requirement is not met. Use of "stakeholder process" in the requirement implies that entities other than the Planning Authority or the Transmission Planner have authority over how the standards are to be met without any financial risk. If the "stakeholder process" language is not removed, SDG&E feels stakeholders involved in the process should be registered with NERC and subject to the same audit requirements and penalties as the Planning Authority or the Transmission Planner. Furthermore, the California Transmission Owners have a FERC approved stakeholder process that is administered by the California ISO. Addition of the term "stakeholder process" in a standard may have unintended consequences.

Balloter	Company	Seg-ment	Vote	Comment
Response: While the SDT believes that SDG&E proposed bullet list is consistent with the footnote as drafted, the list is not as inclusive as the footnote. Therefore, the SDT has retained the existing text and reorganized the footnote for clarity. b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~ The SDT believes that in situations where an entity's planning studies require the interruption of Firm Demand to remain within BES Facility Ratings that the entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be adversely impacted by those decisions have the ability to review those plans. No change made.				
Charles H Yeung	Southwest Power Pool	2	Negative	The second paragraph of the footnote seems to be restricting the use of Demand interruption for the sake of Firm Transfer reduction. This can be stated directly without adding the confusion of re-dispatch. By coupling re-dispatch with a constraint of not shedding Demand, the paragraph also creates confusion as to what to do in a situation where the amount of Demand that is allowed to be shed in the first paragraph could be reduced with re-dispatch. Would re-dispatch not be allowed? We suggest that the paragraph be rewritten as follows: "Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management)."
Response: The SDT has reorganized the footnote to clarify its intent and address this issue. **b)** An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch,				

Balloter	Company	Seg-ment	Vote	Comment
where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~				
Larry Akens	Tennessee Valley Authority	1	Negative	TVA appreciates the SDT's efforts to clarify and improve this complex and challenging area. However, as mentioned in our last comments regarding footnote b, TVA still believes that the SDT's proposal is still focusing more on reliability of local loads than on the overall reliability of the BES. Reliability of local loads should be addressed outside the TPL standards and therefore should not be used/referenced in footnote b. Existing stakeholder processes (referred to in the SDT proposal) typically focus on larger system issues and not on local load serving. TVA believes that some local load should be allowed to be dropped in order to maintain BES reliability. Instead of the proposed footnote b, TVA suggests that the SDT define a "local area" with guidelines detailing the reliability requirements for these local area loads. This would separate the local area load requirements from the BES requirements in the TPL standards.
Ian S Grant	Tennessee Valley Authority	3	Negative	
George T. Ballew	Tennessee Valley Authority	5	Negative	
Marjorie S. Parsons	Tennessee Valley Authority	6	Negative	
Response: The original footnote 'b' focused on local area and limited interruption of Demand. Since individual entities planning philosophies are different across North America, the SDT has been unable to determine a one-size-fits-all definition for local area. Therefore, the SDT adopted an approach that allows entities to utilize input from stakeholders in an open and transparent process. In this way, any affected party has a mechanism to ensure that the planners are planning a reliable BES. No change made.				
Pat G. Harrington	BC Hydro and Power Authority	3	Negative	
Gordon Rawlings	BC Transmission Corporation	1	Negative	
Response: With no comment provided, the SDT is unable to provide a response.				
Gregg R Griffin	City of Green Cove Springs	3	Affirmative	An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will

Balloter	Company	Seg-ment	Vote	Comment
				be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: Interruptible Demand or Demand-Side Management Circumstances where the uses of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.
Response: Thank you for your support.				
Guy V. Zito	Northeast Power Coordinating Council, Inc.	10	Affirmative	1. There is concern with the use of the term Demand. It is unclear throughout the footnote whether or not the term Demand includes Interruptible Demand or Demand-Side Management. It is suggested that interruption of Demand be clarified to not include Interruptible Demand or Demand-Side Management to more clearly show the permitted use of Load shedding. 2. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. 3. Language that mitigation of Load and/or Demand interruption should be pursued within the planning process should be reinstated as reinforcement of a Transmission Providers' planning obligations to their load customers, and system operations. 4. Footnote 'b' should be made to read as follows: b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of Load and/or Demand following Contingency events. Interruption of Load and/or Demand is discouraged and all measures to mitigate such interruption should be pursued within the planning process. However, it is recognized that Load and/or Demand will be interrupted if it is directly served by the elements automatically removed from service by the Protection System as a result of a Contingency. Furthermore, in extraordinary circumstances within the planning process Load and/or Demand may need to be interrupted to address BES performance requirements. When interruption of Load and/or Demand is utilized within the planning

Balloter	Company	Seg-ment	Vote	Comment
				process to address BES performance requirements, such interruption is limited to: • Circumstances where the use of Load and/or Demand interruption are documented, including alternatives evaluated; and where the Load and/or Demand interruption is made available for review in an open and transparent stakeholder process. If Load and/or Demand interruption is necessary, planning should indicate the amount needed, and not specify how it would be obtained. What Load and/or Demand is interrupted is an operational decision. 5. Additional comments not included in the material listed for footnote 'b' on the Comment Form. In the paragraph below the bullets in footnote 'b', confusion is introduced through the use of the term "firm Demand". It is unclear how this is different than the defined term "Firm Demand" and what the implications of the term "firm Demand" are. This footnote should not discourage such adjustments which actually increase the reliability of service to end users. 6. The last sentence of footnote 'b' is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own.

Response: 1. The SDT has reorganized the footnote to clarify its intent and address this issue.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

2. The SDT has reorganized the footnote to clarify its intent and address the issue raised.

Balloter	Company	Seg-ment	Vote	Comment
3. & 4. The SDT addressed these concerns by including the phrase "including alternatives evaluated" and does not believe that it is appropriate to dictate that the planners must evaluate "all measures to mitigate" annually or the specific details concerning documentation of alternatives. **5.** The SDT has corrected the capitalization errors. **6.** Since the planned action of curtailing of firm transfers may adversely impact neighboring systems, the SDT believes that it is important in this situation to articulate a condition that is normally implied. No change made.				
Ajay Garg	Hydro One Networks, Inc.	1	Affirmative	Hydro One is casting an affirmative vote on the revisions to Table 1, footnote 'b' in TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. However, we believe the proposed language might be confusing and should be modified to read as follows: "b) It is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Interruptible Demand or Demand-Side Management o Circumstances where the uses of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the interruption of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected." Note that the voting system does not permit to enter re-lined comments. We can provide a red-lined document with our proposal upon request.
David L Kiguel	Hydro One Networks, Inc.	3	Affirmative	
Response: The SDT believes that the sentences deleted in your proposed footnote are necessary to provide context for the items that follow and has crafted the language to provide a balance between flexibility and consistency across NERC. The SDT has reorganized the footnote to clarify its intent. b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.				

Balloter	Company	Seg-ment	Vote	Comment
~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~				
Henry Ernst-Jr	Duke Energy Carolina	3	Affirmative	The effective date in the Implementation Plan needs to be changed to match the Effective Date in the standards, in order to clarify the allowed interruption of Non-consequential load before the new Footnote 'b' takes effect.
Response: The effective dates in the Implementation Plan match those in the standards. No change made.				
Mark B Thompson	Alberta Electric System Operator	2	Abstain	While the AESO does not generally disagree with the intent of the proposed change, we have voted "abstain". In particular, as reflected in the adopted Alberta Reliability Standard TPL-002-AB-0, no loss of Demand and Generation have been given equal consideration for Category B contingencies. In addition, within the Alberta energy market structure and the operation of the transmission system, there are no firm transfers on transmission facilities in Alberta.
Response: Individual jurisdictions are allowed to have more restrictive standards and therefore, this revision to the standard does not dictate that a jurisdiction must change its requirements. The SDT recognizes that there may be areas or markets that do not utilize terms contained within the standard.				

Consideration of Comments

TPL Table 1 Order – Project 2010-11

The TPL Table 1 Order Drafting Team thanks all commenters who submitted comments on the revision of TPL-002 footnote 'b' and TPL-001 footnote 12. These standards were posted for a 30-day public comment period from July 31, 2012 through August 29, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 51 sets of comments, including comments from approximately 117 different people from approximately 81 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

Due to comments received, the SDT has made the following changes to the text:

- Effective date – updated to latest approved language
- Main footnote
    - Grammatical change from 'should be' the intent to 'is' the intent.
    - Clarified the near-term and long-term requirements.
    - Defined the ceiling threshold as 75 MW.
- Attachment 1
    - Section I
        - Clarified that an existing process can be utilized, as long as it meets the criterion in Section I.
        - Changed 'all affected stakeholders' to 'affected stakeholders'.
        - Changed 'specific applications' to 'specific locations'.
        - Added statement that says that the process does not have to be repeated in subsequent years if conditions haven't changed.
    - Section II
        - Item 2.b has been clarified to better show the SDT's intent.
        - Item 8 has been changed from 'planners' to 'Transmission Planners and Planning Coordinators and clarified to indicate that it includes both the local and adjacent entities.
    - Section III
        - Clarified role of regulatory authority.
        - Deleted role of Regional Entity.
        - Defined the ceiling threshold as 75 MW.
- Footnote 12 only – Corrected terminology to use 'Non-Consequential Load loss' instead of 'Firm Demand interruption'.

The SDT is requesting that this project be moved forward to the initial ballot and comment phase of the process.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Sunitha Kothapalli	Puget Sound Energy	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joseph (Joe) W Seabrook	Transmission Contracts	WECC	1, 3, 5
2.	Peter (Pete) M Jones	Transmission Contracts	WECC	1, 3, 5
3.	Kebede Jimma	Transmission Planning	WECC	1, 3, 5
4.	Gary Shumate	Transmission Planning	WECC	1, 3, 5
5.	Harris Wayne	Transmission Planning	WECC	1, 3, 5
6.	Carol Jaeger	Transmission Planning	WECC	1, 3, 5
7.	Zachery (Zach) Sanford	Transmission Planning	WECC	1, 3, 5
8.	Eleanor Ewry	Transmission Planning	WECC	1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael R. Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Team	X	X	X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	Robert Rhodes	Southwest Power Pool	SPP	NA
	John Allen	City Utilities of Springfield	SPP	1, 4
4.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

5. Harold Wyble	Kansas City Power and Light Company	SPP	1, 3, 5, 6
6. Katy Onnen	Kansas City Power and Light Company	SPP	1, 3, 5, 6
7. Don Taylor	Westar	SPP	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
4.	Group	Bob Steiger	Salt River Project	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Brian Keel	SRP	WECC	1

				1	2	3	4	5	6	7	8	9	10
5.	Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2. CHUCK LAWRENCE	ATC	MRO	1
3. TOM BREENE	WPS	MRO	3, 4, 5, 6
4. JODI JENSON	WAPA	MRO	1, 6
5. KEN GOLDSMITH	ALT	MRO	4
6. ALICE IRELAND	XCEL	MRO	1, 3, 5, 6
7. DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8. ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9. JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10. SCOTT NICKELS	RPU	MRO	4
11. TERRY HARBOUR	MEC	MRO	5, 6, 1, 3
12. MARIE KNOX	MISO	MRO	2
13. LEE KITTELSON	OTP	MRO	1, 3, 4, 5
14. SCOTT BOS	MPW	MRO	1, 3, 5, 6
15. TONY EDDLEMAN	NPPD	MRO	1, 3, 5
16. MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17. DAN INMAN	MPC	MRO	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
6.	Group	Jim Kelley	SERC EC Planning Standards Subcommittee	X				X					

Additional Member	Additional Organization	Region	Segment Selection
1. John Sullivan	Ameren	SERC	1
2. Bob Jones	Southern Company Services	SERC	1
3. Pat Huntley	SERC	SERC	NA
4. Darrin Church	TVA	SERC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Group	Jason Marshall	ACES Power Member Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ashley Gonyer	East Kentucky Power Cooperative	SERC	1, 3, 5
2.	Noman Williams	Sunflower Electric Power Corporation	SPP	1
3.	David Albers	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chuck	Matthews	WECC	1
2.	Allen	Chan	WECC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Individual	Tim Ponseti, VP	TVA Transmission Reliability Engineering & Controls	X		X		X	X			X	
10.	Individual	Antonio Grayson	Southern Company										
11.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
12.	Individual	Brandy A. Dunn	Western Area Power Administration	X					X				
13.	Individual	Aaron Staley	Orlando Utilities Commission	X									
14.	Individual	Chifong Thomas	BrightSource Energy, Inc.					X					
15.	Individual	Jose H Escamilla	CPS Energy	X		X		X					
16.	Individual	Mark Westendorf	MISO		X								
17.	Individual	Jennifer Wright	San Diego Gas & Electric	X		X		X					
18.	Individual	Patrick Brown	Essential Power, LLC					X					
19.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				
20.	Individual	John Burnett	Los Angrles Department of Water and Power	X		X		X					
21.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
22.	Individual	Michael Falvo	Independent Electricity System Operator		X								
23.	Individual	Kirit Shah	Ameren	X		X		X	X				
24.	Individual	Thad Ness	American Electric Power	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
25.	Individual	John Delucca	LCEC (Lee County Electric Cooperative	X		X							
26.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
27.	Individual	James Tucker	Deseret Generation & Transmission Cooperative	X		X		X					
28.	Individual	Brian Keel	Salt River Project	X		X		X	X				
29.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
30.	Individual	Anthony Jablonski	ReliabilityFirst										X
31.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
32.	Individual	Milorad Papic	Idaho Power Co.	X		X							
33.	Individual	Martyn Turner`	LCRA Transmission Services Corporation	X									
34.	Individual	Jonathan Fidrych	Tri-State Generation & Transmission Association, Inc.	X		X		X					
35.	Individual	John Martinsen	Public Utility District No. 1 of Snohomish County	X		X	X	X	X				
36.	Individual	Robert W. Creighton	Nova Scotia Power	X									
37.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
38.	Individual	Chris de Graffenried	Consolidate Edison Co. of NY, Inc.	X		X		X	X				
39.	Individual	Charlie Pottey	Sierra Pacific Power Co d/b/a NV Energy	X		X		X					
40.	Individual	Richard Vine	California Independent System Operator		X								
41.	Individual	charlie pottey	nevada power company dba nvenergy	X		X		X					
42.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
43.	Individual	Chris Scanlon	Exelon	X		X		X	X				
44.	Individual	Catherine Mathews	NorthWestern Energy (NWMT)	X		X		X					
45.	Individual	Robert Casey	Georgia Transmission Corporation	X									
46.	Individual	Kathleen Goodman	ISO New England Inc.		X								
47.	Individual	Bangalore Vijayraghavan	PG&E Company	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
48.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
49.	Individual	Steve Myers	Electric Reliability Council of Texas, Inc.		X								
50.	Individual	Ed O'Brien	Modesto Irrigation Districtt			X	X		X				
51.	Individual	R. Peter Mackin	Utility System Efficiencies, Inc.								X		

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: Thank you for following the new method of commenting that helps to avoid needless duplication of effort for the SDT. Your company name will be included in the participant list and the comments in full will be reviewed by the drafting team members under the Salt River Project comment/response.

Organization	Yes or No	Support Comments Submitted by Another Entity
Puget Sound Energy	Agree	Salt River Project
Sierra Pacific Power Co d/b/a NV Energy	Agree	WECC

1. Do you agree with the description and components of the Stakeholder Process in the body of the footnote including the maximum capacity threshold (currently shown as 'x' MW but the SDT will fill in the value after the data request is complete and will submit the value for industry comment and approval in the next posting)? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. For the maximum capacity item, please supply any technical rationale for your comment along with limiting conditions and any current criteria in use at your entity.

Summary Consideration: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a stakeholder process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach.

Several commenters suggested that there should be no limitation on the amount of Load that could be shed under footnote 'b'. The SDT does not agree with this suggestion, as such an important consideration cannot be left open-ended. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW.

Several commenters asked about the distinction between long-term and near-term with respect to the use of footnote 'b'. The SDT has clarified the language to show that footnote 'b' is available for long-term planning as well as near-term planning but that the stakeholder process only needs to be used for near-term.

The following changes were made due to industry comments:

First sentence of footnote text: An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events.

Next to last sentences in footnote text: In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1.

Organization	Yes or No	Question 1 Comment
Salt River Project BrightSource Energy, Inc. Los Angrles Department of Water and Power Deseret Generation & Transmission Cooperative California Independent System Operator nevada power company dba nvenergy PG&E Company Utility System Efficiencies, Inc.	No	We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest deleting this sentence.Assigning a fixed “not to exceed” number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others.A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, “[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events”. It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fix maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving “safe harbor” to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the “not to exceed” amount.

Organization	Yes or No	Question 1 Comment
ACES Power Member Standards Collaborators	No	We disagree with placing an upper limit on the amount of firm load shed. Conceptually, it seems like a good idea but we do not believe that such a threshold could ever consider all of the potential issues that could arise and would cause the need to plan to shed firm load. This is especially true considering that the SAR clarifies that the upper threshold will be based on the existing planned load shedding values. Future issues cannot be considered by such a data request. Consider a situation in which a new transmission line was included in Planning Assessment but cannot be built because right of ways cannot be obtained. Should an upper limit be placed on planned load shed in such a situation?
Bonneville Power Administration	No	BPA does not support quantitative limits on planned interruption, as planners generally do not plan the system to interrupt demand for a single contingency. As stated in the proposed footnote b, "[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events." Setting a quantitative limit would push transmission planners to plan the system to meet such a limit for a single contingency in all cases. Moreover, a quantitative limit would be difficult to implement due to the wide variety of system configurations and conditions. BPA believes an appropriate amount would be dependent on the topography and the size of the system being planned.
Manitoba Hydro	No	The maximum limit 'x' MW should vary with system load level and voltage. For example, an 'x' MW interruption would be a very small fraction of a 5000 MW system load level compared to a 1000 MW load level. Similarly, interruption of 'x' MW could be equal to surge impedance loading of a 230 kV line, where as it would be a fraction of a EHV transmission line loading.
NorthWestern Energy (NWMT)	No	Comments: A fixed maximum number of MW for Non-Consequential Load

Organization	Yes or No	Question 1 Comment
		Loss should not be used in an industry-wide standard. There is too much diversity. We suggest that a fixed maximum number not be stipulated.
Response: The SDT does not agree with this suggestion, as such an important consideration cannot be left open-ended. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW.		
SERC EC Planning Standards Subcommittee	No	We do not agree with this approach since there is no technical basis for allowing load shedding. It is all an administrative process which could result in inconsistencies from area to area. If a single contingency results in a local network becoming temporarily radial, then load shedding within the local network should be allowed. A limitation of up to some maximum amount of load shedding (to be determined) should be imposed. This would provide a technical basis for load shedding, which would help ensure consistency.
Southern Company	No	Southern does not agree with this Stakeholder Process approach since there is no technical basis for allowing load shedding. It is all an administrative process which could result in inconsistencies from area to area. A more technical based approach was the one taken by the SDT in an earlier draft - temporarily radial concept. If a single contingency (Category B) results in a local network becoming temporarily radial, then load shedding within the local network should be allowed since it would not have any impact to the reliability of the transmission grid. A limitation of up to some maximum amount ('x' MW) of load shedding (to be determined) should be imposed. This would provide a technical basis for load shedding, which would help ensure consistency from area to area. Furthermore, this would provide a method for defining the "fringes" of the power system.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed		

Organization	Yes or No	Question 1 Comment
Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. The SDT agrees with you that there should be an upper limit on the amount of Firm Demand that can be shed. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW.		
TVA Transmission Reliability Engineering & Controls	No	TVA believes that the Stakeholder process is burdensome and should not be required for all levels of footnote b use. TVA beleives that the Stakeholder process should only be used for larger amounts of planned load drop. TVA would like to propose the following: For load loss of less than 50 MW - only TP approval is required; for load loss up to 100 MW - PC approval is required; for load loss up to 300 MW - RRO approval is required. Any load loss over 300 MW would require both RRO & NERC approval. The Stakeholder process would be required for any load loss of 100 MW or more. TVA is basing these levels using OE-417 as a starting point - which must be filed for an uncontrolled load loss of 300 MW as well as load shedding of 100 MW or more implemented under emergency operational policy. TVA believes that the 300 MW is the maximum amount of load that can be dropped without obtaining special permission from both NERC and the RRO.
Response: The SDT does not agree with this suggestion, as the Order 762 data request showed that there were no utilizations of		

Organization	Yes or No	Question 1 Comment
footnote ‘b’ involving more than 75 MW. Therefore, the SDT has set the proposed ceiling on footnote ‘b’ utilization at 75 MW. The data request also showed that the average value of footnote ‘b’ utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW.		
MISO	No	Transmission planning that relies on planned or controlled interruption of non-consequential firm load following loss of a single transmission facility should not be acceptable and removal of footnote 12 should be considered or a modification to allow its use only in conjunction with a petition to FERC to waive (on an exception basis) the requirement to maintain firm load service for a specifically identified system configuration issue warranting Footnote 12’s application. If it is determined that a footnote provision is required in the standard, we agree with the description and components of the Stakeholder Process in the body of the footnote, but reserve judgment on the value of the “x” that sets the maximum amount of MW load loss. Also, we have comments on the reference to Attachment I. Please see our comments under Q5.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote ‘b’ and with footnote 12 in TPL-001-2. The Commission’s Order No. 762 found that NERC’s proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process (“footnote b”), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC’s proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a stakeholder process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. The Order 762 data request showed that there were no utilizations of footnote ‘b’ involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote ‘b’ utilization at 75 MW.		

Organization	Yes or No	Question 1 Comment
See response to Q5.		
San Diego Gas & Electric	No	We don’t support the changes.
Public Utility District No. 1 of Snohomish County	No	
Response: Without any reasons being supplied, the SDT is unable to respond to this comment.		
Essential Power, LLC	No	Although we agree with the majority of the content of the footnote, we’re not sure that using a specific amount of load as the bright-line threshold is appropriate. For example, if we make the limit 25 MW, this will have a different impact on different entities, in different regions. For a small TP that may only have a total of 200 MW of load, 25 MW is a significant amount of their overall obligation. For an area with 40,000 MW of load, 25 MW is hardly significant. Additionally, the nature of the load must be taken into consideration as well. Some types of load are more acceptable to lose than others; again, this may vary from region to region.Although we don’t have a specific recommendation or solution regarding these issues, I would urge the SDT to take these into consideration in their next revision. The sentence that starts with “When interruption of Firm Demand is utilized...” is confusing as it seems this sentence should only refer to the limited circumstances mentioned within footnote b
Response: The Order 762 data request showed that the average value of footnote ‘b’ utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. No change made. The SDT believes that in context the sentence you reference is clear; no change made.		
Tacoma Power	No	The layout of Table 1 with “No 12” does not actually indicate that load loss is allowed for those specific contingencies. Also the wording of the

Organization	Yes or No	Question 1 Comment
		footnote appears to require all Non-Consequential Load Loss to go through the attachment 1 process, not just P1.1 to P1.5, P2.1 and P3.1 to P3.5. Instead P1.1 to P1.5 and P3.1 to P3.5 should say “Yes per Attachment I” and Footnote 12 should be eliminated entirely. Since P2.1 is a new requirement with Version TPL-001-03, the recent NERC survey did not capture utilities currently using Non-Consequential Load Loss to address opening a line without a fault. Furthermore, some utilities may not identify problem lines until their first assessment using TPL-001-3. P2.1 should have a new footnote reading “For this contingency, load which is served radial from a remaining single source line may be shed as if it were Consequential load.” Technical Background: Parallel transmission lines serving remote load commonly will not perform with a P2-1 contingency, particularly when the strong source is opened. These issues are particularly common with load in rural settings and the cost to meet urban reliability expectations will be disproportionally expensive. Utilities will be encouraged to configure their system radially, which will be less reliable to meet this rare contingency. FERC has not specifically addressed load shedding associated with open ended lines. In order 693 the Commission was responding to the contingencies in TPL-001-1 that included footnote b. In order 762 and the NOPR RM12-1-000, FERC continues to reference applicability of footnote b to the TPL-001 defined single contingencies, but was otherwise prepared to accept Firm Load Loss for the single contingencies in TPL-001-2 P2.2 to P2.4. In the TPL-001-2, the category of “P2-Single Contingency” expanded to include both a new contingency of an open ended line, and various bus and breaker faults that previously were considered as Multiple Contingency.Based on our experience the likelihood of a line opening is significantly less than for line equipment faults. In addition, during human error caused line open events, personnel are on-site to affect quick restoration. This standard should not impose an upper limit because any planned large

Organization	Yes or No	Question 1 Comment
		load shedding will be reviewed and approved by the applicable regulatory authority. Pending the survey outcome, a limit of 3000 MW consistent with the CIP-002-5 Critical Asset level may be useful if the SDT believes an upper limit is needed.
Response: The SDT believes that the layout of Table 1 is clear in its intent that the circumstances covered by footnote 12 permit Load loss by exception and that the footnote pertains only to those Contingency types where the footnote appears. No change made. Although P2.1 is a "new" event, the resulting system will be the same as that following many P1.2 events; therefore, the SDT does not see a need to add a new footnote to P2.1. No change made. The SDT does not agree with this suggestion, as such an important consideration cannot be left open-ended. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW.		
Independent Electricity System Operator	No	Specific to the language used in footnote b, we agree with the concept of an approval process for determining the acceptable level of Firm Demand interruption applicable in a jurisdiction, and do not agree with prescribing a fixed MW threshold for a continent-wide acceptable Firm Demand interruption.Therefore, we recommend removing the last sentence in footnote b) which reads "In no case can the planned Firm Demand interruption under footnote 'b' exceed 'x' MW." and also the same sentence from Attachement 1 section III. We believe there should not be a fixed limit on the amount of Firm Demand interruption, for reasons explained below in answers to Questions 4 and 5. As part of a reliability standard, the footnote should clarify the conditions under which load curtailment will be allowed, including mention of processes necessary to manage special circumstances. We generally agree with the reference to Attachment 1, but have concerns

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>about the components of the Stakeholder Process described in Attachment 1, for reasons described in answers to Questions 2, 3 and 4.</td></tr>
<tr><td colspan="3">Response: The SDT does not agree with this suggestion, as such an important consideration cannot be left open-ended. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote ‘b’ involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote ‘b’ utilization at 75 MW.

See responses to Questions 2, 3, 4, and 5.</td></tr>
<tr><td>Ameren</td><td>No</td><td>We believe that the NERC Glossary contains an adequate definition for Firm Demand, which does not include Interruptible Demand or Demand-Side Management Load. We do not believe that Interruptible Demand or Demand-Side Management Load needs to be mentioned in the footnote b) as these types of Demand are not Firm Demand. Interruptible Demand can be cut at any time and may contain Demand-Side Management components, and may be direct controlled by the System Operator.</td></tr>
<tr><td colspan="3">Response: The SDT believes that mention of Interruptible Demand and Demand-Side Management Load within footnote ‘b’ adds further clarity. No change made.</td></tr>
<tr><td>American Transmission Company</td><td>No</td><td>ATC agrees with the ‘x’ MW statement in footnote ‘b’ , however, supports a maximum threshold value of 300 MW because this is the load loss threshold that the DOE deems to be significant enough to warrant a NERC system event investigation.</td></tr>
<tr><td colspan="3">Response: The SDT does not agree with this suggestion. The Order 762 data request showed that there were no utilizations of footnote ‘b’ involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote ‘b’ utilization at 75 MW.</td></tr>
<tr><td>Salt River Project</td><td>No</td><td>Additional comment from SRP for Q #5.</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
Consolidate Edison Co. of NY, Inc.	No	See reply to Question 5
Response: Please see response to Q5.		
Lincoln Electric System	No	LES suggests the following changes to Footnote B/12 to further clarify the drafting team's intent. Under Footnote B/12, recommend the first sentence be modified to state "An objective of the planning process is to minimize the likelihood and magnitude of interruption...". Additionally, please clarify the reference to the Near-Term Transmission Planning Horizon while remaining silent on the Long-Term Transmission Planning Horizon. Does Appendix 1 apply to the Long-Term Transmission Planning Horizon as well as the Near-Term Transmission Planning Horizon?
Response: The SDT agrees with your suggested substitution of the word "is" for the words "should be" in the first sentence of the footnote. An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. The SDT has clarified the language to show that footnote 'b' is available for long-term planning, as well as near-term planning, but that the stakeholder process only needs to be used for near-term. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1.		
LCRA Transmission Services Corporation	No	Footnote 12 is applied in column labeled "Non-Consequential Load Loss Allowed." However, the last sentence of the proposed Footnote 12 switches from using the terms Consequential Load Loss and Non-Consequential Load Loss to using the term "Firm Demand." The term "Firm Demand" should be revised to "non-Consequential Load Load loss."

Organization	Yes or No	Question 1 Comment
		In addition, the application of Footnote 12 to the P3 contingency category should be removed.
Response: The SDT agrees with your change and will use the term "Non-Consequential Load loss." The SDT does not agree that footnote 12 should be removed from the P3 Contingency category. The SDT clarifies that the Planning Events for which footnote 12 is applicable were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011) in its consideration of TPL-001-2. The proposed changes are outside the scope of this project, which aims to clarify the stakeholder approval process. No change made.		
Tri-State Generation & Transmission Association, Inc.	No	There are several points that we disagree with in terms of the Stakeholder Process in the body of the footnote. First, the footnotes are not written in a manner so as to clearly be only applicable to Planning Standards. Many parts of the footnotes and the Attachment I can be misconstrued as Operational requirements. For example, the sentence that states "Curtailment of firm transfer..." should state "Planned curtailment of firm transfer..." Second, we disagree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest removal of this sentence.Assigning a fixed "not to exceed" number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others.A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, "[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events". It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fixed

Organization	Yes or No	Question 1 Comment
		maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Lastly, in an effort to develop a clearer and more transparent compliance standard, it is recommended that the additional requirements imposed by this footnote be broken into separate requirements set forth within the body of the standard itself. Do not imbed requirements in footnotes.
Response: Because this footnote can only be applied to this specific standard, there should be no confusion as to the applicability to planning. No change made. The SDT does not agree with this suggestion, as such an important consideration cannot be left open-ended. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW. The SDT disagrees with your characterization that requirements are being imbedded within the footnote. The requirement is clearly stated within the body of the standard. The footnote is simply clarifying those special circumstances where some relief from a strict interpretation of the requirement is permitted. No change made.		
Hydro-Quebec TransEnergie	No	Comments: It is difficult to establish the maximum value for acceptable Firm Demand interruption. For example, an entity may have an acceptable maximum load loss to avoid impacts on the grid such as generation trip-outs. For Hydro-QuÃ©bec TransÃ‰nergie (HQT), in the QuÃ©bec Interconnection, this value is above 1,000 MW. No maximum value should be posted in Footnotes 12 and 'b', since it is specifically related to system design and Interconnection size (inertia). Let us keep in mind that the goal of the TPL standards is not service continuity of local loads but global reliability of the system. Even though service continuity is important, TPL

Organization	Yes or No	Question 1 Comment
		standards should not address this issue by posting a maximum allowable load loss. Moreover, HQT considers that a Stakeholder Process such as seen in Attachment I has no place in a standard and its footnotes. Mainly, the Stakeholder Process doesn't consider that entities may have their own regulatory authorities with different processes, which do not specifically establish this load loss value.
Response: The SDT does not agree with this suggestion, as such an important consideration cannot be left open-ended. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW. Industry and the NERC BOT have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The SDT is now attempting to address FERC's concern expressed in their Remand Order 762 that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process, is vague, unenforceable, and not responsive to the previous Commission directives on this matter. The draft posted for comment adds detail and specificity to the already-approved approach. The SDT does not believe it appropriate to move away from the industry and BOT approved Stakeholder Process approach. No change made.		
Exelon	No	For TPL-001, the wording for footnote 12 does not make clear that DSM would be allowed without the Attachment 1 procedure. ComEd suggests the following wording change:12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to ensure that BES performance requirements are met. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements (other than Interruptible or Demand Side Management load), such interruption is limited to circumstances where the Non-Consequential

Organization	Yes or No	Question 1 Comment
		Load Loss is meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 12 exceed ‘x’ MW. For TPL-002, the wording of footnote “b” is not totally clear that it applies only to non-consequential load shed and not consequential load shed. ComEd suggests that the wording of footnote “b” be changed as shown:b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner’s planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to ensure that BES performance requirements are met. When interruption of Firm Demand (other than in (1) or (2) above) is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote ‘b’ exceed ‘x’ MW.
Response: The SDT believes that footnote 12, as written and taken in context of the entire proposed TPL-001-2a standard, is clear. Similarly, the SDT believes that footnote ‘b’ is clear, as well. No change made.		
ISO New England Inc.	No	For single contingency events, footnote 12 should be eliminated. Planning the electric system for non-consequential load loss as a means to address a single contingency should not be acceptable. If the footnote is to remain, as a minimum the attachment should be

Organization	Yes or No	Question 1 Comment
		changed to increase the emphasis on the near term nature of the use of non-consequential load shedding.
Response: The SDT disagrees with your suggestion to remove footnote 12 because there are some limited situations when considering the entire North American grid where Non-Consequential Load loss may be necessary. No change made. The SDT has clarified the language to show that footnote 'b' is available for long-term planning, as well as near-term planning, but that the stakeholder process only needs to be used for near-term. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1.		
South Carolina Electric and Gas	No	SCE&G does not agree with the proposed modifications to footnote b. SCE&G believes the original footnote b is appropriate and consistent with the Energy Policy Act of 2005.SCE&G cites several statements in the Energy Policy Act of 2005 as justification for our position.1. The Energy Policy Act of 2005 states: "The term 'reliability standard' means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity."It also states, "This section does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services."SCE&G believes the proposed modifications to footnote b will result in building or enlarging facilities to meet the proposed requirements.

Organization	Yes or No	Question 1 Comment
		Also, any requirement that disallows load interruption or limits the amount of load interruption infringes on the stated limitation on the ERO to not set and enforce compliance with standards for adequacy.2. It also states: The term ‘reliable operation’ means operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.”In this statement there is no mention of disallowing the interruption of firm load. It only requires that instability, uncontrolled separation, or cascading failures not occur. SCE&G believes the proposed changes to footnote b are beyond the authority granted to the ERO by the Energy Policy Act.3. It also states: ‘‘Nothing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard, ..."SCE&G believes the proposed modifications to footnote b infringe on the state’s authority to address adequacy and reliability of electric service within the State.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote ‘b’ and with footnote 12 in TPL-001-2. The Commission’s Order No. 762 found that NERC’s proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process (“footnote b”), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC’s proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.		

Organization	Yes or No	Question 1 Comment
Electric Reliability Council of Texas, Inc.	No	As an initial matter, ERCOT does not believe the planning process should allow for non-consequential load shedding under single contingency conditions. However, if the SDT elects to retain a vehicle for such exceptions, it should establish objective, reliability based criteria that lend themselves to inclusion in a reliability standard. This is consistent with the general approach for reliability standards, which prescribe the “what”, not the “how”. If the exceptions are based on objective criteria that are known upfront, and those criteria reflect appropriate reliability based technical justifications, then the risk of unwarranted exceptions to the general prohibition due to misuse of the exception process is mitigated. Furthermore, the exception process should be external to the NERC Reliability Standards (e.g. in the Rules of Procedure), which should merely reference authorized exceptions granted pursuant to that process. In no case should a reliability standard mandate a stakeholder process in any respect, procedural or substantive. In ISO/RTO regions, stakeholder processes fall within ISO/RTO governance matters. These issues are beyond the purview of NERC Reliability Standards. In other regions, although the relevant functional entities do not have stakeholder processes analogous to ISOs/RTOs, any relevant processes are similarly beyond the scope of the reliability standards. Accordingly, the SDT should eliminate all revisions related to the establishment of a stakeholder process. As discussed in response to question 5, FERC is not requiring this approach, but rather has only provided guidance with respect to ways to possibly bring the prior proposal in line with applicable regulatory approval standards for reliability standards. Additionally, as a general matter, substantive reliability standards requirements should not be imbedded within a footnote to a requirement. In this case, not only is there a substantive requirement imbedded in the footnote, there is also a substantial attachment (which must become part of the enforceable standard requirements)...and, to make it worse, the

Organization	Yes or No	Question 1 Comment
		attachment is an attachment to the footnote, rather than an attachment to and referred to by a reliability standard requirement.

Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.

The SDT disagrees with your characterization that requirements are being imbedded within the footnote. The requirement is clearly stated within the body of the standard. The footnote is simply clarifying those special circumstances where some relief from a strict interpretation of the requirement is permitted. No change made.

Organization	Yes or No	Question 1 Comment
Modesto Irrigation Districtt	No	We do not agree with the concept of non-consequential load loss in light of historic application of N-1 criteria, that only provides for consequntial load loss.

Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability

Organization	Yes or No	Question 1 Comment
would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.		
Southwest Power Pool Reliability Standards Development Team	Yes	As a concept we agree with the stakeholder process. We would like clarification on why only the Near Term was used for non-consequential load loss and not both Near and Long term. It seems that depending on the time frame we would be held to different requirements of the standard.
Response: The SDT has clarified the language to show that footnote 'b' is available for long-term planning, as well as near-term planning, but that the Stakeholder Process only needs to be used for near-term. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1.		
MRO NSRF	Yes	The NSRF agrees with the 'x' MW statement in footnote b. The NSRF suggests a maximum threshold value of 300 MW because this is the load loss threshold that the DOE deems to be significant enough to warrant a NERC system event investigation.To support the inclusion of planning to use up to 300 MW of firm load shedding, registered Transmission Planning entities or regional planning entities should provide a TPL type analysis that demonstrates the use of planned firm load shedding allows BES equipment to stay within emergency thermal, voltage, and frequency ranges, and would not cause instability, uncontrolled separation, and cascading as defined in the FPA Section 215.
Idaho Power Co.	Yes	Maximum threshold for Planned Firm Demand interruption should be based on a previous year recorded peak demand. For instance for recorded peak demand of more than 3,000 MW the maximum treshold should be

Organization	Yes or No	Question 1 Comment
		greater than 300 MW.
Duke Energy	Yes	Situations where use of footnote 'b' would be appropriate can't be readily characterized with criteria leading to some "technically justified" maximum capacity threshold for interruption. That being the case, a maximum capacity threshold could be established based upon other criteria, such as the 300 megawatt threshold for DOE disturbance reporting.
Response: The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW.		
Georgia Transmission Corporation	Yes	Please remove the "is" as shown below:"12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to ensure that BES performance requirements are met. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss [IS] meets the conditions shown in Attachment 1. In no case can the planned FirmDemand interruption under footnote 12 exceed 'x' MW."
Response: The SDT agrees with your suggested substitution of the word "is" for the words "should be" in the first sentence of the footnote. An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events.		
LCEC (Lee County Electric Cooperative		"No comment as we have no Firm Demand / Load customers."
American Electric Power	Yes	AEP believes it can support the language at this stage, but would like to

Organization	Yes or No	Question 1 Comment
		revisit this after the MW threshold has been determined.
Arizona Public Service Company	Yes	
Orlando Utilities Commission	Yes	
CPS Energy	Yes	
City of Austin dba Austin Energy	Yes	
Nova Scotia Power	Yes	
Response: Thank you for your support.		

2. **Do you agree with the description and components of the the Stakeholder Process in Section I of Attachment I? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: Comments raised several concerns on the following issues:

Stakeholder process is not needed: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a stakeholder process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach.

Proposed process duplicates or conflicts with existing regulator/RTO processes: The SDT agreed with the comments and revised Footnote 12 accordingly. The text now allows for an existing process to be utilized, as long as it meets the criterion set out in Attachment 1, Section I.

Scope of Stakeholder Participants: Some comments reflected concern that the term "all affected stakeholders" in Attachment 1, Part I was too broad. The SDT has accepted the commenters' view and has deleted 'all'.

Clarification on need for annual Stakeholder Review: Commenters requested clarification as to whether the stakeholder processes has to be repeated for each annual assessment for a project if the process has confirmed for that specific project it is acceptable to curtail a firm demand. The SDT has added language to indicate that the Stakeholder Process does not have to be repeated for each annual assessment if the process has confirmed for a specific project that it is acceptable to curtail a Firm Demand, provided that the parameters have not changed. If any changes have occurred to the original parameters, these issues must then be addressed in the Stakeholder Process before that Planning Assessment can be completed.

Part I 2 b. Public Notification: The SDT agrees with the comment that: "Specific applications of the planned Firm Demand interruption under footnote 12" could be considered to require detailed descriptions of each and every contingency that could lead to use of footnote 'b' and is not necessary for the public notification. The language has been changed to clarify the SDT's intent.

Implementation Plan: Several commenters mentioned that this process could turn out to be lengthy and that the Implementation Plan should take this into account. The Implementation Plan for this project hasn't changed from the one that was submitted with the original filing, and is currently set at 60 months for footnote 'b'.

Dispute resolution process is not required: The SDT concluded that a dispute resolution process is an essential part of the process. The attachment language does not present any constraints on such a process; it just requires that an entity has a method to resolve disputes.

The following changes were made due to industry comments:

Main Body of footnote text: In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1.

Attachment 1 – Section I, last sentence: The responsible entity can utilize an existing process or develop a new process. The process must include the following:

Attachment 1 – Section I, Bullet 1: Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues

Attachment 1 – Section 1, Bullet 2: Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:

Attachment 1 – Section I, Bullet 2b: Specific location(s) of the planned Firm Demand interruption under footnote 'b'

Attachment 1 – Section I, last paragraph: An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

Organization	Yes or No	Question 2 Comment
Salt River Project	No	We suggest removing item 5, "A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction".

Organization	Yes or No	Question 2 Comment
BrightSource Energy, Inc. Los Angrles Department of Water and Power Deseret Generation & Transmission Cooperative nevada power company dba nvenergy PG&E Company Modesto Irrigation District Utility System Efficiencies, Inc.		Given that the "applicable regulatory authorities or governing bodies responsible for retail electric service issues" are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?
Response: The SDT believes that a dispute resolution process is an essential part of the Stakeholder Process. The SDT believes that the dispute resolution process should include a method for accounting for the cost/benefit if it is an issue for the region. The attachment language does not present any constraints on such a process; it just requires that an entity has a method to resolve disputes. No change made.		
MRO NSRF American Transmission Company	No	Order 890 already requires Transmission Planners to solicit the input of affected stakeholders on TPL standards. Order 890 does not provide prescriptive details regarding the stakeholder process for the TPL standards, which includes footnote 'b'. In additions, there is no clear justification to indicate that the process with regard to footnote 'b' warrants more prescription stakeholder process details than the rest of the TPL standards. So, the NSRF suggests that Section II be removed. If Section I is not removed, then NSRF suggests at least replacing "all affected stakeholders" with "all known affected stakeholders" or "appropriate known affected stakeholders" because an entity can develop a list of all known affected entities for compliance purposes and document that the meeting was open to them and that they were notified. An entity cannot demonstrate that a stakeholder meeting is open

Organization	Yes or No	Question 2 Comment
		to unknown stakeholders or that it notified unknown stakeholders.The use of “all” in mandatory zero defect standards is not appropriate in NERC standards, especially when potential large diverse populations such as affected stakeholders must be considered.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote ‘b’ and with footnote 12 in TPL-001-2. The Commission’s Order No. 762 found that NERC’s proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process (“footnote b”), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC’s proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. The SDT has tried to provide some technical/quantitative criteria in Section II to assist affected stakeholders in understanding why Firm Demand is planned to be interrupted. No change made. The SDT has accepted your comment and has replaced “all affected stakeholders” with “affected stakeholders.” Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:		
TVA Transmission Reliability Engineering & Controls	No	Please see comment for question #1. TVA believes that TPs should be able to drop some load without having to go thru a burdensome process. Only the larger load drop levels should require a Stakeholder review.
SERC EC Planning Standards	No	We recommend using a technical basis for load shedding instead of a Stakeholder

Organization	Yes or No	Question 2 Comment
Subcommittee		Process.
Southern Company	No	Southern recommends using a technical basis for load shedding (see comment in Question 1 above) instead of a Stakeholder Process.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. Please also see response to Q1.		
ACES Power Member Standards Collaborators	No	(1) Attachment 1 should clarify that it only applies when approval is not required by the regulatory body with authority over retail service, such as local regulatory authorities and state public utility commissions. This includes whether the approval is required by NERC rules or another regulatory body's rules. It does not make sense for the Transmission Planner or Planning Coordinator to duplicate a process that is already required by another regulatory body that satisfies due process. As an example, why should the Transmission Planner and Planning Coordinator have a dispute resolution process if the regulatory body already has a dispute resolution process that can be used. It also does not make sense for the Transmission Planner and Planning Coordinator to be compelled to have a stakeholder comment process when the local regulatory body's approval is required. Having such a process is duplicative and unnecessary.

Organization	Yes or No	Question 2 Comment
		(2) Many RTOs have well organized stakeholder processes that could be utilized to satisfy Attachment I. Because the TPL standards apply to both the PC and TP, one may believe the both the PC and TP need to have these stakeholder processes. Rather, we think that the TP should be able to rely on its PC's stakeholder process. We suggest Attachment I should clarify that this is acceptable and that both entities are not required to have redundant processes. The most important point is that stakeholders have an opportunity to participate.
Response: The SDT has revised the Stakeholder Process to allow use of an existing regulator/RTO stakeholder process, as long as it meets the criterion in Attachment 1, Section I. The responsible entity can utilize an existing process or develop a new process. The process must include the following: The SDT believes that a dispute resolution process is an essential part of the stakeholder process. No change made.		
Bonneville Power Administration	No	Regarding the stakeholder process and dispute resolution, BPA believes that a decision for Firm Demand interruption needs to be made based on what is best for the system, not a specific dispute resolution process.
Western Area Power Administration	No	The addition of the "Stakeholder Process" outlines in Attachment 1 is so onerous so as to persuade entities NOT to attempt the use of Footnote b) OR 12). Is this the intent?
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does		

Organization	Yes or No	Question 2 Comment
not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.		
MISO	No	(1) The process presented in Section I of Attachment I is overly prescriptive. This Section needs only to stipulate that the proposed utilization of the footnote be reviewed through an open and transparent stakeholder process developed or approved by the Regional Entities (since the RE will eventually need to review and assess the reliability impact of such utilization), with supporting information. (2) There is no basis to support allowing the utilization of the footnote in the Near-Term Transmission Planning Horizon of the Planning Assessment only. The footnote itself leaves the time frame wide open, and does not explicitly or implicitly restrict its utilization to only the Near-Term horizon. Often, in the long-term planning horizon, when approval for transmission addition or reinforcement cannot be obtained for whatever reasons, utilization of the footnote is considered and adopted, subject to stakeholder's and regulatory authority's approvals. Note that it is impractical to add or reinforce transmission facilities in a near-term planning (e.g. Year One) time frame and hence the proposed provision does not allow for utilizing the footnote for the interim period before new or reinforced transmission facilities are put in place. We suggest to remove the word "Near-Term". (3) Requirement 8 of the Transmission Planning Standard TPL-001-3 requires notification and response requirements for a Planning Coordinator and/or Transmission Planner for the Planning Assessment to any registered entity having a reliability interest. Attachment I does not recognize this requirement. Attachment I must be coordinated with this administrative requirement.
Response: (1) Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission		

Organization	Yes or No	Question 2 Comment
remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. (2) The Stakeholder process is required prior to planned interruption of Firm Demand in the near term, but does not preclude application in the long term. The SDT clarified the language concerning near- and long-term applications of footnote 'b'. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. (3) Requirement R8 imposes an obligation on the Planning Coordinator and Transmission Planner to distribute its Planning Assessment to: "any functional entity that has a reliability related need and submits a written request for information …" Requirement R8 does not ensure the functional entity is aware that it may be affected by a plan to curtail firm Load so as to request information. If a Planning Coordinator or Transmission Planner has established a stakeholder process, as per Attachment 1, reporting of such a process under Requirement R8 is not prohibited. No change.		
Public Utility District No. 1 of Snohomish County	No	
San Diego Gas & Electric	No	We don't support the addition of stakeholder process language.
Response: With no reasoning provided, the SDT is unable to respond to this comment.		
Tacoma Power	No	Completing the entire stakeholder process on an annual basis, before the TPL study can be finalized, is not feasible due to long and unpredictable timelines for public involvement and regulatory approval. The stakeholder process should only be repeated when the technical basis as outlined in section II have changed, or when

Organization	Yes or No	Question 2 Comment
		there are new stakeholders. There are cases on the fringes of the system where Firm Demand Interruption as the preferred alternative in both the long term and short term, not as a temporary patch in Corrective Action Plan.To address these issues, Section I should read as:Before the use of Firm Demand interruption is allowed as an element in the Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of this mitigation is reviewed through an open and transparent stakeholder process. The responsible entity shall document the stakeholder process which shall include the following:1. Meetings must be open to all affected stakeholders including applicable regulatory Authorities or governing bodies responsible for retail electric service issues. 2. Notice must be provided in advance of meetings to all affected stakeholders, including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with: a. Date, time, and location for the meeting b. Specific applications of the planned Firm Demand interruption under footnote 12 c. Provisions for a stakeholder comment period 3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote 12 (as shown in Section II below) must be made available to meeting participants. 4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns. 5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction. During each Planning Assessment, the Transmission Planner or Planning Coordinator shall update the information outlined in Section II. If the annual hours of exposure to or the amount of Firm Demand has increase above the previously disclosed level(s), a new Stakeholder process shall be completed within one Calendar year.Every three years the stakeholder process shall reoccur to allow new stakeholders input to the process.
Response: The SDT has not adopted your proposed language: "Before the use of Firm Demand interruption is allowed as an element in the Transmission Planning Horizon of the Planning Assessment," as the SDT believes the reference to the Corrective Action Plan is		

Organization	Yes or No	Question 2 Comment
superior. However, the SDT has added language to indicate that the Stakeholder Process does not have to be repeated for each annual assessment if the process has confirmed for a specific project that it is acceptable to curtail a Firm Demand, provided that the parameters have not changed. If any changes have occurred to the original parameters, these issues must then be addressed in the Stakeholder Process before that Planning Assessment can be completed. An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application. The SDT agrees that application of a stakeholder process could be lengthy and, consequently, has already provided a 60-month implementation plan. No change made. The information in Section II is required as part of the Stakeholder meeting. No change made.		
Manitoba Hydro	No	A stakeholder process should not be required in jurisdictions where a legislation already authorizes interruptions, as consent of stakeholders cannot override legislation. If Firm Demand interruptions require the approval of regulatory authority as described in Section III (for interruptions over 25 MW or if voltage level of the contingency is greater than 300 kV), the stakeholder process described in Section I would become a redundant process. Does Section I exclude Firm Demand interruptions addressed under Section III?
Response: The SDT has revised the stakeholder process to allow use of an existing regulator/RTO stakeholder process, as long as it meets the criterion in Attachment 1, Section I. The responsible entity can utilize an existing process or develop a new process. The process must include the following For interruptions over 25 MW, or if voltage level of the Contingency is greater than 300 kV, then both the Stakeholder Process and the Section III regulatory review are still required.		
Independent Electricity System Operator	No	(1) The process presented in Section I and the rest of Attachment I is overly prescriptive and lengthy. As part of a reliability standard, the footnote and process must focus on the impact that Firm Demand interruption (or Load Rejection) would

Organization	Yes or No	Question 2 Comment
		have on the reliability of the Bulk Electric System and this aspect is covered in Section III. This Section needs only to stipulate that the proposed utilization of the footnote be reviewed through (a) an open and transparent stakeholder process and (b) approved by a relevant reliability authority such as the ERO, Regional Entity or applicable governmental authority since this authority will eventually need to review, assess and approve the reliability impact on the interconnected BES of such utilization, with supporting information. Reliability issues and their assessment and approvals should be dealt with by the applicable reliability authority. Details of other aspects of Firm Demand interruption, mainly the Stakeholder review and approval process and issues pertaining to the quality of service, economic and welfare impacts of Firm Demand interruption, assessment of alternatives (including their economic and welfare impacts), etc. should be dealt with by the regulatory authority or government body of each jurisdiction (in particular, in non-US jurisdictions), as is the normal practice for all other Transmission Planning activities. (2) There is no basis to support allowing the utilization of the footnote in the Near-Term Transmission Planning Horizon of the Planning Assessment only. The footnote itself leaves the time frame wide open, and does not explicitly or implicitly restrict its utilization to only the Near-Term horizon. Often, in the long-term planning horizon, when approval for transmission addition or reinforcement cannot be obtained for whatever reasons, utilization of the footnote is considered and adopted, subject to stakeholders' and regulatory authorities' approvals. Note that it is impractical to add or reinforce transmission facilities in a near-term planning (e.g. Year 0ne) time frame and hence the proposed provision does not allow for utilizing the footnote for the interim period before new or reinforced transmission facilities are put in place. We suggest removing the word "Near-Term".
Response: (1) The SDT believes that the stakeholder process must involve all stakeholders affected and provide specific information of the intended purpose and scope so they can understand the reason for Firm Demand interruption is appropriate. Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability		

Organization	Yes or No	Question 2 Comment
Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. The SDT agrees that application of a stakeholder process could be lengthy and, consequently, has provided a 60-month implementation plan. (2) The Stakeholder process is required prior to planned interruption of Firm Demand, but does not preclude application in the long term. The SDT has clarified the language concerning near- and long-term use of footnote 'b'. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1.		
Ameren	No	We request that Item 1 be modified to include representatives of stakeholders because it may not be practical to open a meeting to all affected stakeholders. The new sentence of Attachment 1 should read, "Meetings must be open to all affected stakeholders, or their representatives, including applicable regulatory authorities or governing bodies responsible for retail electric service issues." Also, requirements for a meeting location would sem to eliminate electronic partipation via webex. It would seem more practical for a TP or PC to host a specific webex to present and discuss the issues associated with the need to drop Firm Demand. Further, we request that a MW threshold be included before the Section I stakeholder process would begin, and believe that a minimum threshold of 10 MW of Firm Demand to be cut would be a reasonable value to initiate a stakeholder process.

Organization	Yes or No	Question 2 Comment
		Levels below 10 MW would be considered as "noise" in the planning horizon. We believe that an approval should be obtained in the Section I process, which would eliminate the need for Section III. By requiring an approval of the appropriate local governing bodies responsible for retail service issues (including rates), there is no need to agree on a cap to limit the amount of Firm Demand dropped.

Response: The SDT agrees that the term "all affected stakeholders" in Attachment 1, Part I is too broad. The SDT has accepted the commenters' view and has replaced "all affected stakeholders" with "affected stakeholders." The SDT has not included stakeholder representatives, as this too would make identification of same impossible.

> Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues

> Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:

The Stakeholder Process in Attachment 1 assumes that a meeting would be held; however, the language does not prohibit the use of other methods acceptable to the stakeholders.

Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.

Organization	Yes or No	Question 2 Comment
Consolidate Edison Co. of NY, Inc.	No	See reply to Question 5

Organization	Yes or No	Question 2 Comment
Salt River Project	No	Additional comment from SRP for Q #5.
Response: Please see response to Q5.		
LCRA Transmission Services Corporation	No	In the Proposed Revision to the Standard, Footnote 12 is applicable to the use of Non-Consequential Load Loss to relieve criteria violations resulting from P1, P2, and P3 category contingencies, however, Footnote 12 and Attachment I switch terms and begins using “Firm Demand.” Though it may be reasonable to characterize Non-Consequential Load Loss as a subset of Firm Demand not all Firm Demand is Non-Consequential Load Loss. The term “Firm Demand” as used in Footnote 12 and Attachment I should be replaced with “Non-Consequential Load Loss.” Application of the term “Firm Demand” in Footnote 12 and Attachement 1 introduces an ecomonic criteria to the TPL-001 Reliability Standard. For intstance, the interruption of “Firm Demand” as defined in the NERC Glossary may not require Non-Consequential Load Loss, however, this is an economic decision between the parties involved in the Firm Demand contract. In addition, a Transmission Planner or Tranmission Owner may or may not be a party to the Firm Demand contract. The process outlined in Attachment 1 applies to the P3 contingency category (through the application of Foontote 12) and thus represents a significant and substantive change in the reliability standard over previous standards. The reference to Footnote 12 should be deleted from the P3 contingency category.
Response: The SDT acknowledges that the references to Firm Demand interruption should reference Non-Consequential Load Loss. The SDT has made revisions to the TPL-001-2a Footnote 12 and Attachment I to show these changes. The SDT clarifies that the planning events for which footnote 12 is applicable were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011) in its consideration of TPL-001-2. The proposed changes are outside the scope of this project, which aims to clarify the stakeholder approval process. No change made.		
Tri-State Generation &	No	We disagree with Section I of Attachment I to the extent that there currently are several other venues through which stakeholder input is mandated. In addition, we

Organization	Yes or No	Question 2 Comment
Transmission Association, Inc.		do not believe NERC Reliability Standards have the authority to dictate stakeholder outreach processes. For several reasons, including the time required for public input, permitting, acquisition, and construction, most transmission projects take several years to build. TPs will develop plans to mitigate BES performance violations, but those plans may not be able to be constructed in time. The Footnotes do not allow planners to design temporary mitigation to accommodate real world construction issues, which are often complex in nature due to competing interests.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. The SDT agrees that application of a stakeholder process could be lengthy and, consequently, has provided a 60-month implementation plan.		
Duke Energy	No	Since item 2 describes the public notice that must be provided, the phrasing of 2.b should be revised to replace the words "Specific applications" with the words "Summary description". "Specific applications" could be considered to require detailed descriptions of each and every contingency that could lead to use of footnote 'b'. That level of detail could certainly be provided to meeting participants, but shouldn't be necessary for the public notice.
Response: The SDT agrees with the comment that: "Specific applications of the planned Firm Demand interruption under footnote		

Organization	Yes or No	Question 2 Comment
12" could be considered to require detailed descriptions of each and every contingency that could lead to use of footnote 'b' and is not necessary for the public notification. The language has been changed to clarify the SDT's intent. Specific location(s) of the planned Firm Demand interruption under footnote 'b'.		
California Independent System Operator	No	The process presented in Section I of Attachment I is overly prescriptive. Identifying the need for stakeholder consultation on this issue within the consultation process already employed by the Transmission Planner or Planning Coordinator should be sufficient detail. In particular, however, we suggest removing item 5, "A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction". Given that the "applicable regulatory authorities or governing bodies responsible for retail electric service issues" are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution? There is no basis to support only allowing the utilization of the footnote in the Near-Term Transmission Planning Horizon of the Planning Assessment. The footnote itself leaves the time frame wide open, and does not explicitly or implicitly restrict its utilization to only the Near-Term horizon. Often, in the long-term planning horizon, when approval for transmission addition or reinforcement cannot be obtained for whatever reasons, utilization of the footnote is considered. Note that it is impractical to add or reinforce transmission facilities in a near-term planning (e.g. Year 0ne) time frame and hence the proposed provision does not allow for utilizing the footnote for the interim period before new or reinforced transmission facilities are put in place. We suggest removing the word "Near-Term".
Response: The SDT has recognized that the requirement to notify all stakeholders is too broad and has replaced "all affected stakeholders" with "affected stakeholders." Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for		

Organization	Yes or No	Question 2 Comment
retail electric service issues Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with: The SDT believes the stakeholder process is required and it must provide specific information of the intended purpose and scope so stakeholders can understand the reason for Firm Demand interruption is appropriate. The SDT has debated the language and believe that it is appropriate. No change made. The Stakeholder Process is required prior to planned interruption of Firm Demand, but does not preclude application in the long term. The SDT has clarified the language concerning near- and long-term use of footnote 'b'. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1.		
Hydro-Quebec TransEnergie	No	The Stakeholder Process doesn't consider that entities may have their own regulatory authorities with different processes, which do not specifically establish load loss values. Also, the use of Firm Demand interruption in the Corrective Plan should not be limited only to the Near-Term Transmission Planning Horizon. It should also be allowed for the Long-Term horizon, at least for Multiple Contingencies.
Response: The SDT has revised the Stakeholder Process to allow use of an existing regulator/RTO Stakeholder Process, as long as it meets the criterion set in Attachment 1, Section I. The responsible entity can utilize an existing process or develop a new process. The process must include the following The Stakeholder process is required prior to planned interruption of Firm Demand, but does not preclude application in the long term. The SDT has clarified the language concerning near- and long-term use of footnote 'b'. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm		

Organization	Yes or No	Question 2 Comment
Demand interruption meets the conditions shown in Attachment 1.		
NorthWestern Energy (NWMT)	No	Comments: It is unclear how the dispute resolution process would treat stakeholders with different concerns. We suggest that Item 5 of Attachment 1 be deleted.
Response: The SDT believes that a dispute resolution process is an essential part of the Stakeholder Process. No change made.		
Georgia Transmission Corporation	No	Item #1 in Section I should be reworded: From This....”Meetings must be open to all affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues.” Reworded to say: “Meetings must be open to all affected NERC Registered Entities including applicable regulatory authorities or governing bodies responsible for retail electric service issues.”The concern is that stakeholders could be too broadly construed including residential, commercial, industrial customers, and even more so (i.e transitory customers). We recommend that the sentence be reworded as shown above. Additionally, GTC request feedback from the SDT's intent. Is a stakeholder meeting required every year a planning assessment is done showing that non-consequential load loss is required?
Response: The SDT believes that the current language is clear and that the suggested change does not add further clarity. No change made. The SDT has added language to indicate that the Stakeholder Process does not have to be repeated for each annual assessment if the process has confirmed for a specific project that it is acceptable to curtail a Firm Demand, provided that the parameters have not changed. If any changes have occurred to the original parameters, these issues must then be addressed in the Stakeholder Process before that Planning Assessment can be completed. An entity does not have to repeat the stakeholder process for a specific application of footnote ‘b’ utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.		

Organization	Yes or No	Question 2 Comment
ISO New England Inc.	No	With regard to Section I, in paragraph I.5, the stakeholder process includes a dispute resolution process. Existing ISO/RTO stakeholder processes are FERC approved and rigorous, requiring a dispute resolution process goes beyond the existing requirements in ISO/RTO tariffs. Item I.5 should be eliminated.
Response: The SDT has revised the stakeholder process to allow use of an existing regulator/RTO stakeholder process, as long as it meets the criterion set in Section I. The responsible entity can utilize an existing process or develop a new process. The process must include the following The SDT concluded that a dispute resolution process is an essential part of the process and no change was made to the process.		
South Carolina Electric and Gas	No	See response to question #1
Electric Reliability Council of Texas, Inc.	No	Please see ERCOT's response to Question 1.
Southwest Power Pool Reliability Standards Development Team	Yes	See comment From question 1
Response: Please see response to Q1.		
Lincoln Electric System	Yes	Although LES agrees in general with the description and components included as part of Section I, we suggest the following wording changes to enhance Section I. Recommend the drafting team delete item 2(c) as it is duplicative of item 4 which is more succinctly worded. Also, recommend additional wording be added to the end of item 3 to provide meeting participants with advanced notice of the information. As an example, "information...must be made available to meeting participants [ten days prior to the meeting]."

Organization	Yes or No	Question 2 Comment
Response: The SDT believes that the current language is clear and that the suggested change does not add further clarity. No change made.		
LCEC (Lee County Electric Cooperative		No comment as although we are a Firm Demand customer of another entity, we have no Firm Demand / Load customers and therefore would not perform the Stakeholder Process
Arizona Public Service Company	Yes	
Orlando Utilities Commission	Yes	
CPS Energy	Yes	
Essential Power, LLC	Yes	
American Electric Power	Yes	
City of Austin dba Austin Energy	Yes	
Idaho Power Co.	Yes	
Nova Scotia Power	Yes	
Response: Thank you for your support.		

3. **Do you agree with the Information for Inclusion in the Stakeholder Process contained in Section II of Attachment I? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach.

Based on industry comment, item 8 of Section II has been modified to clarify that adjacent Transmission Planners and Planning Coordinators are the relevant parties for assessment of potential overlapping use of Firm Demand interruption.

Based on industry comment, item 2.b of Section II has been modified to clarify the SDT's intent. However, the SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Such an assessment is already required under EOP-001-2.1b by the Transmission Operator and Balancing Authority. A similar requirement for the Transmission Planner/Planning Coordinator would rely on the same type of information and sources already required under the EOP standard.

Several commenters had concern about being required to provide the information in Section II, items 1, 2, 3 and 4. The SDT believes that this information is necessary for understanding the reliability impact and for stakeholders to make an informed decision.

The following changes were made due to industry comments:

Attachment 1, Section II, Bullet 2b: Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community

Attachment 1, Section II, Bullet 8: Assessment of potential overlapping uses of footnote 'b' including overlaps with adjacent Transmission Planners and Planning Coordinators

Attachment 1, Section III, last paragraph: Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.

Organization	Yes or No	Question 3 Comment
Southwest Power Pool Reliability Standards Development Team	No	We need clarification on the term planner in item 8 of section 2. Since the term isn't capitalized we would like to know if this was intended to mean Transmission Planner or a adjacent Planning Coordinator for identifying a seams issue. We would like see item 2b of section 2 removed this item isn't relevant to the standard and goes beyond the purpose of this standard. We understand that this is included for curtailment of load during emergency conditions (EOP001 Attach 1) but feel it is unnecessary in planning.
Response: The SDT agrees and item 8 of Section II has been modified accordingly. 8. Assessment of potential overlapping uses of footnote 'b' including overlaps with adjacent Transmission Planners and Planning Coordinators The SDT believes assessment of the impact of Firm Demand interruption to the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community		
Salt River Project BrightSource Energy, Inc.	No	We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the

Organization	Yes or No	Question 3 Comment
Los Angrles Department of Water and Power Deseret Generation & Transmission Cooperative Tri-State Generation & Transmission Association, Inc. California Independent System Operator nevada power company dba nvenergy PG&E Company Modesto Irrigation Districtt Utility System Efficiencies, Inc.		community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the "applicable regulatory authorities or governing bodies responsible for retail electric service issues".
Response: The SDT believes that the provision of customers affected and the duration and assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is not solely administrative and is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been changed to clarify the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community		
MRO NSRF American Transmission Company	No	Order 890 already requires Transmission Planners to solicit the input of affected stakeholders on TPL standards. Order 890 does not provide prescriptive details regarding the information that should be included in the stakeholder process for the TPL standards, which includes footnote 'b'. Stakeholders that participate in stakeholder meeting can ask for any information that they want regarding the

Organization	Yes or No	Question 3 Comment
		proposed use of Firm Demand interruption. They do not need a third party to prescribe what information they need or want. So, the NSRF suggests that Section II be removed. If Section II is not removed, then the NSRF suggests that at least Items 2b, 6, and 8 be removed from the listing. o Item 2b - The scope and content expectation for an assessment of the potential impact of the proposed Firm Demand interruption on the health, safety, and welfare of the community is basically broad, nebulous, and vague. The stakeholders would raise any specific, relevant questions or concerns in these areas if they exist without a prescriptive stipulation for this information in the TPL-002 standard. o Item 6 - The verification of that the TPL performance requirements will be met by the use of Firm Demand interruption is superfluous. Proposal to use Firm Demand interruption to meet the TPL-002 performance requirements would always be the result of identifying (i.e. verifying) what Firm Demand interruption is needed to meet the TPL-002 performance requirements. o Item 8 - Potential overlapping uses of footnot 'b' with adjacent planners will not always exist and would probably be rare. In addition, whenever the situation would exist, then any applicable adjacent planners would be affected stakeholders and would have the opportunity to attend the stakeholder meeting and raise any questions or concerns in that meeting without the stipulation of this information in the TPL-002 standard.

Response: Order 890 is not applicable to all NERC regions and is not a standard. No change made.

The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent.

2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community

Organization	Yes or No	Question 3 Comment
The SDT believes the wording regarding the TPL standards is necessary to ensure the focus on meeting the TPL standard's reliability requirements is not lost and that the end state following interruption of Firm Demand meets those requirements. No change made. The SDT believes application of a wide area view to the use of Firm Demand interruption is necessary to avoid reliability issues that would not be seen by an individual Transmission Planner or Planning Coordinator. There is no standard requirement for adjacent Transmission Planner/Planning Coordinator's to participate in Order 890 type processes therefore it must be addressed. No change made.		
SERC EC Planning Standards Subcommittee	No	We recommend using a technical basis for load shedding instead of a Stakeholder Process.
Southern Company	No	Southern recommends using a technical basis for load shedding instead of a Stakeholder Process.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.		
ACES Power Member Standards Collaborators	No	(1) We disagree with with including the Facilities that will exceed their rating and the applicable contingenices. We think this information should be treated as confidential. It could be used by bad actors to create outages within communities. The risk to the Bulk Electric System is higher than the benefit of sharing this information. (2) We disagree that the Transmission Planner should be required to provide an assessment on the health, safety and welfare of the community. First, the

Organization	Yes or No	Question 3 Comment
		stakeholders will have an opportunity to provide this information through either the Transmission Planner's stakeholder comment process or through the local regulatory agency's stakeholder comment process. Second, these planned interruptions in firm demand are expected to be short in nature so the impacts should be minimal. Third, an assessment on the health, safety and welfare of the community is an unnecessary burden on the utility and is better suited for local governments. Even if the utility should perform such an assessment, health, safety and welfare are ambiguous terms without clear parameters or expectations for the data. Does this mean that the Transmission Planner verifies police stations, fire departments, hospitals and other critical public support agencies are not included in the planned load shed? Most electric providers already do this when developing load shed plans and are likely not going to includes such customers in any load shed plan. Fourth, communities already have plans in place for the interruption of electricity so as long a critical customers are not shed, then the impacts are likely economic in nature. (3) Bullet 3 needs to be clarified that it is not an estimated frequency but rather a historical frequency. How do you estimate a frequency for a new planned load shed? It also needs to be clarified if the historical frequency is all instances within the Transmision Planner's area or just the specific location of the planned load shed. If it is all instances, it further needs to be clarified that it is only within its own TP area. (4) We do not believe that expected duration of the planned load shed should be required. Any duration will likely be a guess. When actual contingencies occur, the time of restoration varies. Consider the recent event in Arizona and Southern California. The report indicated that the TOP thought they could return the 500 kV line that initiated the event in a few minutes. They were unaware that the phase angle was too large to close. The expected duration is too speculative and should not be required. (5) We disagree with the need to include future plans to mitigate the planned load shed in all cases. For remote areas of the system, there simply may not be sufficient load growth to justify any other mitigation.

Organization	Yes or No	Question 3 Comment
		(6) Item 8 should be clarified that it applies only to the Planning Coordinator. The Planning Coordinator should coordinate all of its Transmission Planner's Planning Assessments. This would include evaluating planned load shedding.
Response: 1) The use of Firm Demand interruption and events involved should only affect local area issues and should not create issues for the BES that could be exploited by "bad actors." No change made. 2) The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. As stated, it is something that TP/PC's normally do. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community 3) Any estimate of future performance has to be based on some sort of available historical information, even for a new line/delivery. The SDT believes it is clear that for stakeholders to make an educated decision regarding Firm Demand interruption, the information must be provided for each instance of Firm Demand interruption use within the Transmission Planner/Planning Coordinator's area. No change made. 4) The SDT believes stakeholders need an expectation of the duration in order to evaluate the impact. No change made. 5) Possible future plans could include a decision not to mitigate the need for Firm Demand interruption. No change made. 6) The standard does not dictate who performs the assessment, only that one be performed. No change made.		
Bonneville Power Administration	No	BPA does not support including information under Sections II.2.a and II.2.b, estimated number and type of customers affected, or an assessment of the use of Firm Demand interruption on the health, safety, and welfare of the community as this information does not support reliability of the BES. If footnote b were applied, reliability of the BES is actually assessed by meeting the applicable TPL Standard for a single contingency with loss of load regardless of the type of customers or use of Firm Demand.
Response: The information is necessary to make an informed judgment and assessment, with stakeholder input, as to whether		

Organization	Yes or No	Question 3 Comment
reliability of the BES will be maintained. Evaluation of the consequences of an event is a part of assessing reliability. No change made. The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community		
TVA Transmission Reliability Engineering & Controls	No	Under Item #2 - TVA is not sure how to properly address "health, safety, and welfare of the community" from an regulatory standpoint. Please clarify what this would require - such as number of hospitals without emergency backup, etc? Also please see answer to question #1 - TVA beleives that only larger load drops should require a Stakeholder review.
Response: The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community See response to Q1.		
MISO	No	Again, this Section is overly prescriptive. This Section needs only to stipulate at a high level, the kind of information needed to support the proposed utilization of the footnote, leaving much of the detail to the application process overseen by the Regional Entities (given the RE will eventually need to review and assess the reliability impact of such utilization). We suggest the SDT to reduce this Section, or remove this altogether with appropriate insertion into Section I that address a general need for supporting information to be specified by the RE's review process.

Organization	Yes or No	Question 3 Comment
Independent Electricity System Operator	No	Again, this Section is overly prescriptive. This Section needs only to stipulate at a high level, the kind of information needed to support the proposed utilization of the footnote, leaving much of the detail to the application process overseen by the applicable reliability authority to review and assess the reliability impact of such utilization. We suggest the SDT to reduce this Section, or remove this altogether with appropriate insertion into Section I that address a general need for supporting information to be specified by the RA's review process. Also note that use of a "stakeholder process", as per FERC's concerns, must be crisp and clear.
Response: The SDT believes the information required provides what is necessary for a high-level assessment of the impact of utilizing Firm Demand interruption and is necessary for stakeholders to make an informed decision. No change made.		
Public Utility District No. 1 of Snohomish County	No	
San Diego Gas & Electric	No	We don't support the addition of stakeholder process language.
Response: Without specific comments, the SDT is unable to respond.		
Tacoma Power	No	Item II.2.b Since this is a stakeholder process, each stakeholder can make an assessment for themselves about the effect of Firm Demand interruption on the health, safety and welfare of the community. This requirement is too vague to be enforceable. Item II.5 Particularly in the case of P2.1 contingencies, utilities may not have any plans to eliminate load shedding "at the fringes of various systems" as the FERC NOPR noted would be acceptable.
Response: Stakeholders would not be likely to have all the information required to make an informed decision. The SDT is seeking the appropriate balance between being too vague and too prescriptive. Based on comments received, the wording has been clarified to better show the SDT's intent.		

Organization	Yes or No	Question 3 Comment
2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community There is a requirement to include any mitigation plans, not a requirement to mitigate – doing nothing could be a possible plan. No change made.		
Manitoba Hydro	No	1 a. It would be very difficult to estimate the annual hours of exposure at or above a certain load level. 2 b. An assessment on the health, safety, and welfare of the community should not be part of a reliability assessment - this is purely subjective. 3 & 4. In situations where load interruption is a new proposal, historical data will not be available. What does the SDT expect here? 5. Is there a requirement to mitigate? If there is a requirement to mitigate, the required time frame is not identified.
Response: 1) Planning studies should provide the information necessary as to the Load levels at which the use of Firm Demand interruption would be required. Evaluation of annual Load profiles where the Load level is exceeded would allow estimation of the duration. No change made. 2) The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community 3 & 4) Any estimate of future performance has to be based on some sort of available historical information. Use of similarly situated lines/deliveries allows for estimation of future performance. 5) There is a requirement to include any mitigation plans, not a requirement to mitigate – doing nothing could be a possible plan.		
Ameren	No	We request that Items 5 and 7 also include information regarding estimated costs and schedule for implementation. Any permitting issues associated with the

Organization	Yes or No	Question 3 Comment
		alternatives should also be included. Any previous attempts to build facilities but were blocked should also be part of the record.
Response: Items 5 and 7 do not prohibit inclusion of cost, schedule information, or other project information and it is anticipated these issues would normally be included. The SDT is seeking the appropriate balance between being too vague and too prescriptive. No change made.		
Consolidate Edison Co. of NY, Inc.	No	See reply to Question 5
Salt River Project	No	Additional comment from SRP for Q #5.
Response: Please see response to Q5.		
City of Austin dba Austin Energy	No	Some of the information for inclusion in the Stakeholder Process is too burdensome and of limited value. In particular, 2b and 4 can be deleted because the requested information may not be available -- particularly if it is new load growth.
Response: The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community Any estimate of future performance has to be based on some sort of available historical information. Use of similarly situated lines/deliveries allows for estimation of future performance. No change made.		
LCRA Transmission Services Corporation	No	Requirement 1 only requires that the Transmission Planner provide system load data, however, assumptions about system dispatch are also relevant. Requiring load without dispatch will not provide a complete understanding of the conditions under which Footnote 12 will apply. As a reliability standard, the Transmission Planner is required to find a range of plausible system conditions under which a criteria

Organization	Yes or No	Question 3 Comment
		violation may be resolved. The requirement (1a) to provide an estimate of the exposure creates an overly burdensome requirement to investigate a wider range of possible operating conditions than is currently performed. Requirement 2a and 2b are overly burdensome on at Transmission Planner/Transmission Owner who does not directly serve retail loads by placing a requirement on the Transmission Planner/Transmission Owner to provide data that is outside of its control to develop or maintain.
Response: The SDT believes the information in Section II is sufficient and would bring out any concerns related to dispatch conditions. No change made. Planning studies should provide the information necessary for 1.a as to the load levels at which the use of Firm Demand interruption would be required. Evaluation of annual Load profiles where the Load level is exceeded would allow estimation of the duration. The SDT believes 2.a and 2.b's provision of customers affected and duration and assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording for 2.b has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community		
Duke Energy	No	In Item #8, replace the word "planners" with the words "Transmission Planners".
Response: The SDT agrees, and item 8 of Section II has been modified accordingly. 8. Assessment of potential overlapping uses of footnote 'b' including overlaps with adjacent Transmission Planners and Planning Coordinators		
Hydro-Quebec TransEnergie	No	For example, under 2 b., assessment of the impacts of interruptions on health, safety, or welfare of the community is not information that could be reasonably expected to be available to system planners. All loads may face interruptions from time to time,

Organization	Yes or No	Question 3 Comment
		and the impact on health, safety or welfare is very difficult to identify. This item should be deleted.
Georgia Transmission Corporation	No	GTC does not understand how item #2b of Section II pertains to the Transmission Planner or the Planning Coordinator. These types of assessments are beyond the scope of the Transmission Planner or the Planning Coordinator and if necessary, should possibly be done by the Load Serving Entity.GTC Recommends the SDT remove item #2b, the following sentence:"An assessment of the use of Firm Demand interruption under footnote 12 on the health, safety, and welfare of the community."
Response: Such an assessment is already required under EOP-001-2.1b by the Transmission Operator and Balancing Authority. A similar requirement for the Transmission Planner/Planning Coordinator would rely on the same type of information and sources already required under the EOP standard. The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community		
NorthWestern Energy (NWMT)	No	Comments: The estimated number and type of customers affected is not needed for reliability of the Bulk Power System. We suggest removing Item 2a in Section II of Attachment 1. An assessment of the health, safety, and welfare of the community should not be required. It is too vague and coud present legal problems. We suggest removing Item 2b in Section II of Attachment 1.
Response: The SDT believes provision of customers affected and duration and assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Such an assessment is already required under EOP-001-2.1b by the Transmission Operator and Balancing Authority. The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for		

Organization	Yes or No	Question 3 Comment
understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community		
ISO New England Inc.	No	Section II, Paragraph 2b requires "an assessment of the use of Firm Demand interruption under footnote 12 on the health, safety, and welfare of the community". A great deal of subjectivity and information that is not readily available to the Transmission Planner or Planning Coordinator would be required to accurately access the effect of load shedding on the community as required by 2b. Additionally Paragraphs II.3 and 4 require estimates of the frequency and duration of Firm Demand interruption would be difficult to provide. These requirements should be deleted. These requirements also undermine the deterministic nature of the Planning Standard. Paragraph II.2.5 that requires future plans to mitigate the need for Firm Demand Interruption should be modified to again emphasize the near term nature of single contingency non-consequential load shedding as a Planning option.
Response: Such an assessment is already required under EOP-001-2.1b by the Transmission Operator and Balancing Authority. A similar requirement for the Transmission Planner/Planning Coordinator would rely on the same type of information and sources already required under the EOP standard. The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community Planning studies should provide the information necessary as to the Load levels at which the use of Firm Demand interruption would be required. Evaluation of annual Load profiles where the Load level is exceeded would allow estimation of the duration. Any estimate of future performance has to be based on some sort of available historical information. Use of similarly situated		

Organization	Yes or No	Question 3 Comment
lines/deliveries allows for estimation of future performance. No change made. A purpose of the stakeholder process is to ensure those impacted by use of Firm Demand interruption and the regulators responsible for quality of service have input on its use and the acceptability of the mitigation plan. No additional elaboration on the use of Firm Demand interruption in the standard is necessary. No change made.		
South Carolina Electric and Gas	No	See response to question #1
Response: Please see response to Q1.		
Electric Reliability Council of Texas, Inc.	No	Please see ERCOT's response to question 1 - the NERC Reliability Standards should not contain requirements related to stakeholder processes, whether they are procedural or substantive. If an exception process is retained, it should be outside of the NERC Reliability Standards (e.g. in the Rules of Procedure). ERCOT also provides the following comments on Section II - the ERCOT comments are in parentheses for easy reference and distinction relative to the proposed requirements. II. Information for Inclusion in Item #3 of the Stakeholder ProcessThe responsible entity shall document the planned use of Firm Demand interruption under footnote 'b' which must include the following: - (ERCOT COMMENT: This is all that is needed for this. The documentation would be relative to the objective criteria developed for this purpose.) 1. Conditions under which Firm Demand interruption under footnote 'b' would be necessary:a. System Load level and estimated annual hours of exposure at or above that Load levelb. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency(ERCOT COMMENT: "1" is not necessary if objective criteria are developed as benchmarks for the exception process. In that case, exceptions would only be allowed if the objective criteria were met, regardless of the underlying assumptions related to conditions and contingencies.) 2. Amount of Firm Demand MW to be interrupted with:a. The estimated number and

Organization	Yes or No	Question 3 Comment
		type of customers affectedb. An assessment of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community(ERCOT COMMENT: The considerations reflected in a and b are inappropriate for a reliability standard. Appropriate considerations for reliability standards are related to the reliability performance of the system. The considerations in a and b are more akin to quality of service issues better suited for regional policy discussions. It is not within the purview of the SDT to address those matters.) 3. Estimated frequency of Firm Demand interruption under footnote ‘b’ based on historical performance(ERCOT COMMENT: Historical performance is irrelevant. If the SDT is going to retain revisions that accommodate non-consequential load shedding, then the only relevant metrics are the objective criteria that set the benchmarks for such exceptions.) 4. Expected duration of Firm Demand interruption under footnote ‘b’ based on historical performance(ERCOT COMMENT: See ERCOT response to “3” above.) 5. Future plans to mitigate the need for Firm Demand interruption under footnote ‘b’(ERCOT COMMENT: This is redundant to the requirement in the reliability standards that requires a plan to resolve any violations identified in the planning process. Furthermore, if load shedding is allowed, this requirement doesn’t make sense. Presumably the idea behind allowing these exceptions is to obviate the prospective need for other alternatives. If that is not the case, then there is no need to allow the exceptions, because the transmission upgrades to mitigate the need for load shedding can be established in the planning horizon.) 6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’(ERCOT COMMENT: The basis for the load shedding exception is to provide a means to meet the TPL performance requirements in the context of a planning assessment. Accordingly, this is redundant to the planning assessments, the point of whichis to identify and resolve performance issues.)

Organization	Yes or No	Question 3 Comment
		7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote ‘b’(ERCOT COMMENT: Load shedding exceptions should be based on objective criteria and be reviewed pursuant to a process external to the NERC reliability standards. Alternative discussions could be part of that external process.) 8. Assessment of potential overlapping uses of footnote ‘b’ with adjacent planners(ERCOT COMMENT: It is not clear what this means. Each functional entity performs assessments relative to its own system. This appears to introduce a vague regional transmission planning requirement with no structure or rules for such assessments.)

Response: Please see response to Q1.

1. The SDT believes the information in Section II is necessary for stakeholders to understand the reason Firm Demand interruption use is appropriate and make an informed decision. No change made.

2. The SDT believes the information in section II is necessary for stakeholders to understand the reason Firm Demand interruption use is appropriate and make an informed decision. The SDT believes provision of customers affected and duration and assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording for 2.b has been clarified to better show the SDT’s intent.

> 2b. Assessment of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community

3. and 4. The SDT believes the information in Section II is necessary for stakeholders to understand the reason Firm Demand interruption use is appropriate and make an informed decision. Any estimate of future performance has to be based on some sort of available historical information even for a new line/delivery. The SDT believes it is clear that for stakeholders to make an educated decision regarding Firm Demand interruption, the information must be provided for each instance of Firm Demand interruption use within the Transmission Planner/Planning Coordinator’s area. No change made.

5. The mitigation plan identifies how reliability violations will be avoided in the future where projects or other actions are not available in time or are not cost effective. No change made.

Organization	Yes or No	Question 3 Comment
6. The SDT believes the wording regarding the TPL standards is necessary to ensure the focus on meeting the TPL standard's reliability requirements is not lost and that the end state following interruption of Firm Demand meets those requirements. No change made. 7. Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. 8. The SDT believes application of a wide area view to the use of Firm Demand interruption is necessary to avoid reliability issues that would not be seen by an individual Transmission Planner/Planning Coordinator. The SDT believes assessment for Adverse Reliability Impacts is an appropriate step. However, the SDT has moved this responsibility to the ERO and deleted the Regional Entity from any involvement. Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.		
Orlando Utilities Commission	Yes	Data element 5 should probably read. "List any Future Plans or future system changes to mitigate the need for Firm Demand Interruption under footnote 'b'". There can be cases where there is no planned future project to relive the problem, or it could be expected that load will go down or changes on neighboring systems will relieve the problem.
Response: Possible future plans could include a decision not to mitigate the need for Firm Demand interruption. No change made.		

Organization	Yes or No	Question 3 Comment
LCEC (Lee County Electric Cooperative		No comment as although we are a Firm Demand customer of another entity, we have no Firm Demand / Load customers and therefore would not perform the Stakeholder Process
Arizona Public Service Company	Yes	
CPS Energy	Yes	
Essential Power, LLC	Yes	
American Electric Power	Yes	
Lincoln Electric System	Yes	
Idaho Power Co.	Yes	
Nova Scotia Power	Yes	
Response: Thank you for your support.		

4. **Do you agree with the Instances for which Approval of Interruptions is required in Section III of Attachment I? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The 25 MW threshold for requiring regulatory authority review was questioned by several entities. The original 25 MW threshold came from the Registry Criteria for Load-Serving Entities. The data request showed that the average value of footnote 'b' utilization was approximately 19 MW. Therefore, the SDT has decided to leave the process threshold at 25 MW.

Several entities questioned having the 300 kV threshold for Contingencies because it has no material impact to Load and that the threshold should be based on a MW amount only. The SDT believes that the 300 kV threshold is appropriate, as the proposed TPL-001-2, which was accepted by industry and the NERC Board of Trustees, made a distinction between HV and EHV and the handling of Contingencies based on the 300 kV level. The SDT believes that the establishment of this threshold within footnote 'b' is consistent with that approach and places the proper emphasis on EHV.

Several entities had concerns that actions from a regulatory body won't happen quickly enough and that such a requirement was not appropriate for a reliability standard. There were also concerns voiced about inconsistencies in such an approach. The SDT understands these concerns and has clarified the language to assist in alleviating such concerns. The SDT also advises any entity wishing to utilize footnote 'b' in its planning process to start that process at an appropriate time so that it can be completed by the needed date.

Some concerns were raised about the role of the Regional Entity in this process. After reviewing the submitted comments, the SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency.

The following changes were made due to industry comments:

Attachment 1, Section III, first paragraph: Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b' if either:

Attachment 1, Section III, last paragraph: Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.

Organization	Yes or No	Question 4 Comment
Southwest Power Pool Reliability Standards Development Team	No	Need clarification around why the 25MWs threshold on generation was thrown into load interruption topic. Looking at the registry criteria for generation the threshold should be 20Mws for a single unit and 75 MWs for aggregated units. Not sure where the 25MWs threshold came from for generation. The 25 MW threshold in Section III is duplicative of the registration limit for generation in the ERO Statement of Compliance Registry Criteria. It is submitted for comment at this time but will not be finalized until after the above mentioned data request is complete and the final value will be submitted for industry comment and approval in the next posting. The GOP registration criteria is 20MWs. Whereas the registration criteria for LSEs and DPs is 25MWs. There appears to be some co mingling of criteria. Additionally this raises the question of whether x =25MWs. Please clarify which you intended to use. We are concerned that getting retail service regulatory authority approval in a quick manner could be difficult. We are also concerned that if it does get caught in the process of being approved and there is no time to construct, that we would not want to be found out of compliance due to something that is out of our control.

Response: The 25 MW threshold came from the Registry Criteria for Load Serving Entities, not from Generator Owners and Operators. The data request showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW.

The SDT has modified the footnote to require regulatory authority review, rather than approval. This should help alleviate some of the concerns. An entity wishing to utilize footnote "b" should start the review process at an appropriate time so that it will be completed by the required date.

> Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b' if either:

Organization	Yes or No	Question 4 Comment
Salt River Project	No	While we do agree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to give approval of the use of Firm Demand interruption under footnote 'b'. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load.
Response: The SDT believes that the request is consistent with existing practices and is in line with an appropriate response to the Order. No change made. The 25 MW threshold came from the Registry Criteria for Load Serving Entities, not from Generator Owners and Operators. The data request showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. No change made.		
MRO NSRF	No	The NSRF suggests that Section III be removed for the following reasons. o The types of transmission projects that would be needed to avoid proposing the use of the Firm Demand interruption under footnote 'b' are expected to be high cost, long lead time Corrective Action projects. Therefore, consideration of the any necessary approvals from regulatory authorities or governing bodies responsible for approving the Corrective Action project is a prerequisite and essential to any discussion or stiputlations regarding disapproval of the use of footnote 'b' proposal. The proposed TPL-002 text for Section III does not include any language to address this crucial aspect of any footnote 'b' approval sipulations. o The diversity of applicable regulatory authorities and governing bodies, as well as their justicitional scope or criteria with respect to the approval of interrupt retail electic service (as well as transmission Corrective Action projects), are too diverse and complex to be appropriately addressed by proposed Approval stipulations in the

Organization	Yes or No	Question 4 Comment
		TPL-002 standard. If Section III is not removed, then the NSRF suggests the following changes. o Include the subject of approvals of Corrective Action projects that are necessary to negate the need for approval of the proposed Firm Demand interruption. o Replace the criteria regarding the voltage level of the relevant Contingency with criteria regarding the amount and type of Firm Demand that would be subject to interruption. The voltage level of the applicable Contingency elements are not material to impact on the affected load. o Replace the applicable amount of Firm Demand interruption criteria from 25 MW to at least 100 MW. There are many radial fed loads that are much geater that 25 MW and there are no stackholder meetings and required approvals for allowing the loads to be fedd radially (subject to interruption for Category B contingencies) rather than being network fed. The DOE threshold for requiring formal system event analysis is 100 MW of load dropping. So, why should the TPL-002 standard required special approvals to allow less than 100 MW of load be subject to interruption to assure BES reliability? o Change the text of “in Year One of the Planning Assessment” to “in the ten year planning horizon of the Plannign Assessment”. The planning assessments may reveal that the need to use of Firm Demand interruption will occur in Year 2, Year 3 or beyond (e.g. when a significant previously unforecast load increase is forecast to occur before any needed Corrective Action project could be initiated and implemented). o The NSRF is concerned that the current wording, “Corrective Action in Year One of the Planning Assessment” could be interpreted to require an annual stakeholder process review and approval. The NSRF suggests that the standard drafting team provide some language regarding a specific period that is expected for reaffiming the approval of the Firm Demand interruption. A review interval of at least every five years should provide reasonable business certainty and allow for future transmission

Organization	Yes or No	Question 4 Comment
		construction if needed. The specific defined period of review should allow entities to operate in an effective manner. The NSRF is also concerned about the condition where approval was granted and then removed. Would an entity be instantly non-compliant to the TPL standards? If this is a possibility, the Standard Drafting Team should add a grace period that allows an entity to credibly construct a project to remain compliant.
American Transmission Company	No	ATC recommends that Section III be removed for the following reasons. o The types of transmission projects that would be needed to avoid proposing the use of the Firm Demand interruption under footnote 'b' are expected to be high cost, long lead time Corrective Action projects. Therefore, consideration of the any necessary approvals from regulatory authorities or governing bodies responsible for approving the Corrective Action project is a prerequisite and essential to any discussion or stipulations regarding disapproval of the use of footnote 'b' proposal. The proposed TPL-002 text for Section III does not include any language to address this crucial aspect of any footnote 'b' approval stipulations. o The diversity of applicable regulatory authorities and governing bodies, as well as their jurisdictional scope or criteria with respect to the approval of interrupt retail electric service (as well as transmission Corrective Action projects), are too diverse and complex to be appropriately addressed by proposed approval stipulations in the TPL-002 standard. If Section III is not removed, then ATC recommends the following changes. o Include the subject of approvals of Corrective Action projects that are necessary to negate the need for approval of the proposed Firm Demand interruption. o Replace the criteria regarding the voltage level of the relevant Contingency with criteria regarding the amount and type of Firm Demand that would be subject to interruption. The voltage level of the applicable Contingency elements

Organization	Yes or No	Question 4 Comment
		are not material to impact on the affected load. o Replace the applicable amount of Firm Demand interruption criteria from 25 MW to at least 100 MW. There are many radially fed loads that are much greater than 25 MW and there are no stakeholder meetings or required approvals for allowing the loads to be fed radially. The DOE threshold for requiring formal system event analysis is 100 MW. So, ATC believes the TPL-002 standard should not require special approvals to allow less than 100 MW of load to be interrupted to assure BES reliability. o Change the text of "in Year One of the Planning Assessment" to "in the ten year planning horizon of the Planning Assessment". The planning assessments may reveal that the need to use of Firm Demand interruption will occur in Year 2, Year 3 or beyond (e.g. when a significant previously unexpected load increase is forecast to occur before any needed Corrective Action project could be initiated and implemented). o ATC is concerned that the current wording, "Corrective Action in Year One of the Planning Assessment" could be interpreted to require an annual stakeholder process review and approval. ATC suggests that the standard drafting team provide some language regarding a specific period that is expected for reaffirming the approval of the Firm Demand interruption. A review interval of at least every five years should provide reasonable business certainty and allow for future transmission construction if needed. The specific defined period of review should allow entities to operate in an effective manner.

Response: If you have already gotten approval from regulatory bodies in your planning process, then Section III is basically already accomplished, and carrying out the remaining details should not be burdensome. No change made.

While it may be true that regulatory authorities and governing bodies are diverse and complex, they are representing their area of responsibility. What may be acceptable in one area, may not be acceptable in another. This is determined by the appropriate authorities. No change made.

The SDT does not believe approvals from regulatory authorities or governing bodies responsible for approving the Corrective Action project is a prerequisite or essential. The focus of this portion of the standard is dropping Load and when approval is necessary.

Organization	Yes or No	Question 4 Comment
There is no benefit in including approval of Corrective Actions. No change made. The proposed TPL Standard (TPL-001-2) makes a distinction in the requirements based on the voltage level of the Contingency studied. This is based on the belief that transmission lines 300 kV and above are for bulk power transfers, and lower voltage lines are more for Load serving. The SDT believes that when a higher voltage line Contingency causes the need for Load dropping, it should require approval. No change made. The data request also showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. No change made The text regarding Year One of the Planning Assessment just means that approval from the appropriate regulatory bodies is needed at least one year before that Load shed is planned for. This does not mean that the need for dropping Load cannot be determined in the study of a future year or that approval cannot be sought sooner. The intent of the SDT was that a review must be obtained one time from the appropriate regulatory body. It does not need to be reviewed again unless the situation changes. The SDT has changed the wording to the following: Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b' if either: The proposed TPL-001-2 accommodates this concern regarding circumstances beyond the control of the Transmission Planner or Planning Coordinator in Part 2.7.3 of Requirement R2.		
SERC EC Planning Standards Subcommittee	No	We recommend using a technical basis for load shedding instead of a Stakeholder Process. However, if a Stakeholder Process is used, the approval thresholds are correct. The Stakeholder Process should not even be initiated for less than these threshold levels.
Southern Company	No	Southern recommends using a technical basis for load shedding instead of a Stakeholder Process. However, if a Stakeholder Process is used, the approval thresholds given in the draft seem appropriate. Furthermore, we believe the Stakeholder Process should not even be initiated for less than these threshold levels.

Organization	Yes or No	Question 4 Comment
		Lower amounts of load and lower voltage contingencies do not need to be taken through a Stakeholder Process.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.		
ACES Power Member Standards Collaborators	No	(1) What is the justification for selecting a 300 kV contingency as a threshold for requiring local regulatory agency approval? What if the planned load shed is only for 1 MW? If a threshold is required, we think it should be based on load size rather than contingency size? (2) What is the justification for selecting 25 MW of planned firm load interruption as a threshold for requiring local regulatory approval? The threshold could be set based off of the accompanying Section 1600 data request. Since there are likely not many instances, it could be required for any new instance that exceeds the existing planned load shed amounts. Thus, the threshold would be set just above existing planned load interruptions. (3) A disclaimer should be added to clarify that an entity may still have to seek local regulatory agency approval per the local regulatory agency's rules. Nothing in the NERC standard will change the local regulatory agency's rules. (4) What if the local regulatory agency does not want to address the planned load

Organization	Yes or No	Question 4 Comment
		shed in the planning time frame? What is the Transmision Planner required to do? While it is likely a local regulatory agency would be interested in addressing a planned load interruption, nothing in the NERC or Commission rules can compel a local regulatory agency to address such matters in a specific time frame. (5) Bullet 1.a is confusing. Is it intended to say that if two Elements are part of a contingency and the Elements have different voltage classes, the Element with the lowest voltage class must exceed the 300 kV threshold? If this is the case, the bullet needs further clarification because it does not state this clearly. (6) The first paragraph after section III appears to contradict bullets 1 and 2. Bullets 1 and 2 place contingency and load thresholds on the planned firm load interruption. However, this paragraph says that the regulatoy body responsible for retail electric service must approve the planned load shed before it can be used in Year One of the planning assessment. If the purpose is for the thresholds to apply beyond Year One and any instance in Year One to require approval, then the language regarding the thresholds needs to clarify that the thresholds apply beyond Year One only. (7) We think it is redundant for the Regional Entity to evaluate planned interruptions of firm load in its footprint. The Planning Coordinator has a wide area view and is already required to do this for its footprint. The Planning Coordinator already works with its neighbors to evaluate impacts. Requiring this evaluation by the Regional Entities is arbitrarily based on historical and political boundaries. Many Planning Coordinators have views that are broader than the Regional Entity view because they are in multiple regions. If this evaluation will be required on a regional basis, why won't it be required on an interconnection? (8) The evaluation required by the Regional Entity may be completed before planned load interruption is approved by local regulatory body. The TP and PC must submit the data based on their plan before the local regulatory body approves the planned load interruption. The Regional Entity must complete its evaluation within 45 days of receiving the information. There is no obligation for the local regulatory body to act within 45 days. Wouldn't it make more sense to evaluate the planned load shed after

Organization	Yes or No	Question 4 Comment
		it is approved by the local regulatory body?

Response: (1) The proposed TPL Standard (TPL-001-2) makes a distinction in the requirements based on the voltage level of the Contingency studied. This is based on the belief that Transmission lines 300 kV and above are for bulk power transfers, and lower voltage lines are more for Load serving. The SDT believes that when a higher voltage line Contingency causes the need for Load shed, it should require approval even if it is only 1 MW.

(2) The data request showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. No change made.

(3) There is no need for such a disclaimer in a NERC Standard. An entity has to abide by other applicable rules outside of the standard. No change made.

(4) The SDT has modified the footnote to require regulatory authority review, rather than approval. This should help alleviate some of the concerns. If the local regulatory agency does not want to address the planned Load shed, then they are giving their tacit approval to the Load shedding.

> Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b' if either:

(5) Yes. For 1.a to apply, the Element with the lowest system voltage level must be 300 kV or above. The SDT believes the wording is clear. No change made.

(6) The text regarding Year One of the Planning Assessment just means that approval from the appropriate regulatory bodies is needed at least one year before that Load shed is planned for. This does not mean that the need for dropping Load cannot be determined in the study of a future year or that approval cannot be sought sooner.

(7) The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency.

> Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of

Organization	Yes or No	Question 4 Comment
whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption. (8) No. The planned Load shed should not be reviewed by the local regulatory body unless it has been determined that there are no Adverse Reliability Impacts.		
Bonneville Power Administration	No	Regarding Section III.2 as stated above, BPA does not support quantitative limits on planned interruption, as planners generally do not plan the system to interrupt demand for a single contingency. Setting a quantitative limit would push transmission planners to plan the system to meet such a limit for a single contingency in all cases.
Response: The SDT does not agree that setting a quantitative limit would push Transmission Planners to plan the system to meet such a limit for a single Contingency in all cases. The footnote states that an objective of the planning process should be to minimize the likelihood and magnitude of Load shed. However, a quantitative limit is needed to ensure that unreasonable amounts of Load shed are not proposed. No change made.		
TVA Transmission Reliability Engineering & Controls	No	Please see answer to question #1. TVA believes that the requirements of 25 MW as well as any Bulk contingency over 300-kV is much too burdensome. TVA beleives that only larger load drops should require a Stakeholder review.
Response: Please see response to Q1.		
Arizona Public Service Company	No	AZPS does not agree that approval by the Regional Entity should be required. Once the process has been fully vetted by the stakeholders, including the regulatory authority for retail service, there is absolutely no need for Regional Entity approval. There would be no adverse affect of non-consequential load tripping on the BES. No reason for Reginal Entity involvement.
Response: The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency.		

Organization	Yes or No	Question 4 Comment
Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote ‘b’, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption.		
BrightSource Energy, Inc. Los Angrles Department of Water and Power Deseret Generation & Transmission Cooperative California Independent System Operator nevada power company dba nvenergy PG&E Company Modesto Irrigation Districtt Utility System Efficiencies, Inc.	No	While we do not disagree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to approval of the use of Firm Demand interruption under footnote ‘b’. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load. Requiring the Regional Entity to approve the Non-Consequential Load Loss under footnote b in TPL-002 (Footnote 12 in TPL-001-3) is duplicative and would increase the work load of the Regional Entities without improving reliability. The TP and PC are already required to make available to the affected stakeholders, verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’ (see Section II.6) and the assessment of potential overlapping uses of footnote ‘b’ with adjacent planners” (see Section II.8), it is hard to imagine what type of review and verification is required to show that “there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity’s footprint”.
Response: The SDT believes that the request is consistent with existing practices and is in line with an appropriate response to the Order. No change made. The 25 MW threshold came from the Registry Criteria for Load Serving Entities, not from Generator Owners and Operators. The data request showed that the average value of footnote ‘b’ utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. No change made.		

Organization	Yes or No	Question 4 Comment
The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency. Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.		
MISO	No	We generally agree with the instances for which approval or interruptions is required, but do not agree with the requirement to seek regulatory approval.In general, when the footnote is proposed to be utilized as an interim measure until transmission facilities can be added or reinforced, regulatory approval must be sought in advance. Having this requirement in a reliability standard not only is unnecessary, but also introduces regulatory requirements (which provides no reliability benefit or basis) in a reliability standard. NERC reliability standards should focus only on BES reliability, not any regulatory requirements. Section III should therefore stipulate a high-level requirement for the proposing entity to submit the proposal to the RE for review and concurrence. Along with the submission, the RE may require the proponent to include a copy of appropriate regulatory approval (which the entity should have already obtained). The conditions (1) and (2) for seeking regulatory approval can be retained, but now become the criteria for seeking review and concurrence by the RE. Additionally, Attachment 1 requires that the ERO develop a methodology on evaluation criteria to be published for determining Adverse Reliability Impacts for approval by the ERO. Planning Assessments are performed on an annual basis. The Attachment 1 process and ERO methodology may require a lengthy approval process that must be repeated on an annual basis.
Response: The SDT has modified the footnote to require regulatory authority review rather than approval. This should help alleviate some of the concerns. Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority		

Organization	Yes or No	Question 4 Comment
or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote ‘b’ if either: The SDT has added language to indicate that the Stakeholder Process does not have to be repeated for each annual assessment if the process has confirmed for a specific project that it is acceptable to curtail a Firm Demand, provided that the parameters have not changed. If any changes have occurred to the original parameters, these issues must then be addressed in the Stakeholder Process before that Planning Assessment can be completed. An entity does not have to repeat the stakeholder process for a specific application of footnote ‘b’ utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.		
Essential Power, LLC	No	This solution requires filing with a regulatory body for any extra interruptions. This seems to be a lot of effort and language for a contingency event that the system is supposed to be able to handle.
Response: The SDT believes that the stakeholder process is necessary to ensure that Load shed is utilized for single Contingencies only under limited circumstances. No change made.		
Tacoma Power	No	As noted in our response to question 2, regulatory approval is often a slow process and is not conducive to repeating annually. Instead of a 25 MW limit, a 300 MW limit that corresponds to the reporting level of firm demand in EOP-004 is more appropriate.
Response: The SDT has added language to indicate that the Stakeholder Process does not have to be repeated for each annual assessment if the process has confirmed for a specific project that it is acceptable to curtail a Firm Demand, provided that the parameters have not changed. If any changes have occurred to the original parameters, these issues must then be addressed in the Stakeholder Process before that Planning Assessment can be completed. An entity does not have to repeat the stakeholder process for a specific application of footnote ‘b’ utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.		

Organization	Yes or No	Question 4 Comment
The data request showed that the average value of footnote ‘b’ utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. The Order 762 data request showed that there were no utilizations of footnote ‘b’ involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote ‘b’ utilization at 75 MW.		
Manitoba Hydro	No	The Section III states that regulatory authority approval is required for interruptions over 25 MW or if voltage level of the contingency is greater than 300 kV. However, a regulatory authority cannot approve interruption of Firm Demand unless it already has such jurisdiction that is conferred upon them by legislation. A reliability standard cannot confer that jurisdiction. Further, the regulator is already part of the proposed stakeholder group and will have input into the proposal. The Section III requires the Regional Entity to review the proposed use of Firm Demand interruption under footnote ‘b’. What impact does it have on the Regional Entity to necessitate a review, if the stakeholders have already agreed to a process, TPL Reliability Standards performance requirements have been verified as in Section II.6, and potential overlapping uses have been assessed with adjacent planners as in Section II.8. What criteria will the Regional Entity use to make their assessment of Adverse Reliability Impacts and potential cumulative effects given the above TPL performance must be met? This requirement can lead to inconsistent decisions between regions.
Response: The SDT believes that the request is consistent with existing practices and is in line with an appropriate response to the Order. No change made. The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency. Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote ‘b’, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption.		

Organization	Yes or No	Question 4 Comment
Independent Electricity System Operator	No	We generally agree with the instances for which approvals or interruptions are required. Approval is to be granted by the Reliability Coordinator or applicable reliability authority. (1) In general, when the footnote is proposed to be utilized as an interim measure until transmission facilities can be added or reinforced, regulatory approval must be sought in advance. Having this requirement in a reliability standard not only is unnecessary, but also introduces regulatory requirements (which provides no reliability benefit or basis) in a reliability standard. NERC reliability standards should focus only on BES reliability, not any regulatory requirements. Section III should therefore stipulate a high-level requirement for the proposing entity to submit the proposal to the Reliability Coordinator for review and concurrence. The conditions (1) and (2) for seeking explicit regulatory approval can be retained, but now become the criteria for seeking review and concurrence by the applicable reliability authority. (2) We suggest deleting Item 1 in the first paragraph (with its a and b bullets) and just indicating that planned Firm Demand interruption requires approval if it is greater than 25 MW (or other threshold). Requirements for approval of the use of Firm Demand interruption should be independent of the voltage level of the contingency. (3) We propose deleting the sentence in the second paragraph “In no case can the planned Firm Demand interruption under footnote ‘b’ exceed ‘x’ MW”. A fixed limit on the allowable size of Firm Demand interruption can not be technically justified for the whole continent and each case should be assessed to determine if its impact on reliability of the bulk transmission system is acceptable or not. The impact of each case on the affected customers (economic, welfare, etc.) will also be reviewed and approved by the regulatory authority or governmental body of each jurisdiction and a “reliability” standard must not impose limits and restrictions pertaining to these aspects. (4) The third paragraph proposes that the Regional Entity should review each case of Firm Demand interruption and verify that there are no Adverse Reliability Impacts.

Organization	Yes or No	Question 4 Comment
		We propose instead that the transmission planner or planning coordinator study the BES performance requirements and the reliability impacts of Firm Demand interruption, including its correct operation, miss-operation, and the failure to operate. The transmission planner should then submit a report of this assessment to the Reliability Coordinator for review and approval.
Response: (1) Regulatory review is not always sought in advance. The SDT believes this review is necessary when the planned Load shed exceeds either of the thresholds in Section III. No change made. 2) The proposed TPL Standard (TPL-001-2) makes a distinction in the requirements based on the voltage level of the Contingency studied. This is based on the belief that transmission lines 300 kV and above are for bulk power transfers, and lower voltage lines are more for Load serving. The SDT believes that when a higher voltage line Contingency causes the need for Load shed, it should require approval even if it is only 1 MW. No change made. (3) The SDT does not agree with this suggestion, as such an important consideration cannot be left open-ended. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote ‘b’ involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote ‘b’ utilization at 75 MW. (4) The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency. Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote ‘b’, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption.		
Ameren	No	We do not believe that section III is needed, and particularly if an approval is included as part of the section I process. We do not subscribe to dropping Firm Demand (non-consequential load) for single contingency events, and do not see a need to include a voltage threshold as part of the contingency requirements. All single contingencies in Category B should be

Organization	Yes or No	Question 4 Comment
		applicable.
Response: Section 3 directly addresses concerns raised by FERC contained in the remand of the TPL standard. Items 1 and 2 are included to further define and "put a box" around the situations where first Contingency Load shedding could be employed. Having the ERO review the application of footnote 12 will provide needed continent-wide consistency. The proposed TPL Standard (TPL-001-2) makes a distinction in the requirements based on the voltage level of the contingency studied. This is based on the belief that transmission lines 300 kV and above are for bulk power transfers and lower voltage lines are more for Load serving. The SDT believes that when a higher voltage line Contingency causes the need for load dropping, it should require approval even if it is only 1 MW. No change made.		
ReliabilityFirst	No	ReliabilityFirst has a major issue/concern with Attachment 1, Section 3 (specifically the last paragraph regarding approval). This section requires the Regional Entity to review each proposed use of Firm Demand interruption under footnote 12 in order to verify that there are no Adverse Reliability Impacts. The paragraph goes on to require the Regional Entity to make its determinations and evaluation of Adverse Reliability Impacts using a published methodology approved by the ERO. First, since the Regional Entity is not a user, owner or operator of the BES, ReliabilityFirst believes the Regional Entity should not have requirements placed upon them. Furthermore there is no guidance on what is required to be placed within the published methodology. ReliabilityFirst believes this verification is outside the Regional Entity scope as delegated by the ERO. ReliabilityFirst believes that if such verification by the Regional Entity is required, it should be specifically laid out in the NERC Rules of Procedure and not an attachment within a standard.
American Electric Power	No	AEP is concerned that not all Regional Entities are the same in regards to their engineering and planning staff, and is not confident that they would all have the resources necessary to perform the required analysis. AEP is concerned by any attempt to require that a Regional Enity adhere to processes and prodecures that have not yet been established. FERC has made comments in the past regarding requirements places upon regional entities (RRO), and while this standard does not

Organization	Yes or No	Question 4 Comment
		yet apply, is does indirectly obligate them to rules and procedures not yet established.
Response: The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency. Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.		
Consolidate Edison Co. of NY, Inc.	No	See reply to Question 5
Salt River Project	No	Additional comment from SRP for Q #5.
Response: Please see response to Q5.		
City of Austin dba Austin Energy	No	The 25 MW threshold for Approval of Interruptions of Firm Demand under Footnote 'b' is too low. It should be increased to 50 MW because there is an elaborate Stakeholder process to work through the reliability concerns.
Response: The data request showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. No change made.		
Lincoln Electric System	No	For item 1(b) in Section III, LES requests that the drafting team clarify why approval by the regulatory authority for a generator contingency is based on the high-side voltage of the GSU rather than the generator capacity. LES believes the generator capacity, rather than the high-side voltage of the GSU, provides a more consistent basis for determining necessity for approval from the applicable regulatory authority or governing body. Additionally, LES asks for further clarification as to whether the steps referenced for

Organization	Yes or No	Question 4 Comment
		Year One of the Planning Assessment extend to Year Two and beyond.
Response: The SDT disagrees that generator capacity is a better basis for determining the necessity for review. The requirements within the TPL standards have different performance levels based on a 300 kV voltage threshold for the Contingency. This distinguishes Facilities generally constructed to transmit power from Facilities used to distribute power to Load centers. The SDT believes this to be a better basis for determining what is important enough to require review from regulatory authorities. No change made. The text regarding Year One of the Planning Assessment just means that review from the appropriate regulatory bodies is needed at least one year before that Load shed is planned for. This does not mean that the need for dropping Load cannot be determined in the study of a future year or that review cannot be sought sooner.		
LCRA Transmission Services Corporation	No	See previous comments about use of the term “Firm Demand”.
Response: Please see previous response.		
Tri-State Generation & Transmission Association, Inc.	No	We disagree with the instances for which Approval of Interruptions is required as proposed by Section III of Attachment I. TPs will develop plans to mitigate BES performance violations, but those plans may not be able to be constructed in time. The reason being that the time required to construct a project to mitigate the issues can take several years. This is due to the need for public input, permitting, acquisition, and construction. Attachment I does not allow planners to design temporary mitigation to accommodate real world construction issues, which are often complex in nature due to competing interests. Attachment I also states that “Before a Firm Demand interruption under footnote ‘b’ is allowed to be utilized as an element of a Corrective Action Plan in Year One of the Planning Assessment...” The need for approval seems burdensome such that it does not allow for temporary mitigation to meet BES performance criterion while other avenues are explored and vetted. The intent of Section III is genuine, but we feel that it is over-reaching for a NERC

Organization	Yes or No	Question 4 Comment
		Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to approval of the use of Firm Demand interruption under footnote 'b'. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load.
Response: The SDT has modified the footnote to require regulatory authority review, rather than approval. This should help alleviate some of the concerns. An entity wishing to utilize footnote "b" should start the review process at an appropriate time so that it will be completed by the required date. Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b' if either: Section III is not requiring action from the regulatory authority. It requires action from the Transmission Planner or Planning Coordinator. The 25 MW threshold came from the Registry Criteria for Load Serving Entities, not from Generator Owners and Operators. The data request showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. No change made.		
Duke Energy	No	Section III is confusing. Are the last two paragraphs of Attachment 1 supposed to be part of Section III? These paragraphs, when read in combination with the first paragraph of Attachment 1, seem to say that any time a Firm Demand interruption using footnote 'b' or footnote 12 shows up in the Near-Term Transmission Planning Horizon, the Stakeholder Process must be invoked. It would seem more reasonable to invoke the Stakeholder Process only when such interruption occurs in Year One of

Organization	Yes or No	Question 4 Comment
		the Planning Assessment.
Response: The last two paragraphs are intended to be included in Section III. The SDT believes it is more appropriate to require the stakeholder process whenever load interruption is planned in the Near-Term Transmission Planning Horizon. That allows more time for all interested parties to be informed.		
Hydro-Quebec TransEnergie	No	For example, in 1a., it is not clear what is meant by "the stated performance criteria regarding allowances...". Why is it necessary to give this kind of explanation? In 1b., the use of the term "non-generator step up transformer" is unusual. Suggest rewording 1b to read:For a generator or generator step up transformer outage Contingency, the extra high voltage (EHV) limit applies to the BES connected voltage (high-side of the Generator Step Up transformer). For any other transformer outage Contingency, the EHV limit applies to the low-side winding (excluding tertiary windings).
Response: In the context of the complete sentence, the SDT believes that the comment is clear. No change made. The terminology is consistent with the Board of Trustees approved TPL-001-2. No change made.		
NorthWestern Energy (NWMT)	No	Comments: A NERC Standard should not require action from a regulatory authority to approve the use of Firm Demand interruption. There is too much diversity in regulatory authorities over the industry-wide area. This would increase the work load of the Regional Entities without improving reliability. We suggest removing Section III of Attachment 1.
Response: The SDT has modified the footnote to require regulatory authority review, rather than approval. This should help alleviate some of the concerns.. Before a Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under		

Organization	Yes or No	Question 4 Comment
footnote 'b' if either: Section 3 directly addresses concerns raised by FERC contained in the remand of the TPL standard. Items 1 and 2 are included to further define and "put a box" around the situations where first Contingency Load shedding could be employed. The SDT believes that an evaluation by the ERO of the potential for adverse system impacts is needed to provide continent-wide consistency. Therefore, Section III is needed. No change made.		
Georgia Transmission Corporation	No	GTC would appreciate if the SDT could please clarify if the approval of a regulatory authority or governing body is referring to the Regional Entity.The first sentence in Section III:"Approval of the use of Firm Demand interruption under footnote 12 by the applicable regulatory authority or governing body responsible for retail electric service issues is required if either:..."
Response: No, that sentence refers to regulatory authorities such as a state public service commission.		
ISO New England Inc.	No	Section III describes the instances where Approval of Interruptions of Firm Demand are required under footnote 12. It is not clear whether under Paragraph III.1.a and Paragraph III.1.b the Transmission Planner is to base the determination on either contingency or both contingencies i.e. is "and" logic to be applied or is "or" logic used? Paragraph III.2 requires such approval for interruption equal to or greater than 25 MW, this is a very small amount of load to be required to bring to a stakeholder approval process for second contingency events. This amount should be increased to at least 100 MW. Additionally in Section III, it is not clear who the "regulatory authority or governing body responsible for retail electric service issues" is. Having this requirement in a reliability standard not only is unnecessary, but also introduces regulatory requirements in a reliability standard. NERC reliability standards should focus only on BES reliability, not any regulatory requirements. The Attachment goes on to state "The Regional Entity determinations of Adverse Reliability Impacts are to be evaluated by the Regional Entity through a published methodology approved by the ERO". This is essentially a "fill in the blank" requirement and makes it necessary to

Organization	Yes or No	Question 4 Comment
		comment and approve the footnote attachment without the benefit of reviewing a proposed methodology.
Response: Section 3 clarifies the criteria for the application of footnote 12. Items 1 and 2 are included to further define and "put a box" around the situations where first Contingency Load shedding could be employed; as such, they are an "or" requirement and the 'or' has been added to the Attachment. The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency. Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption. The regulatory or governing body should be known by the entity who plans to use footnote 12.		
South Carolina Electric and Gas	No	See response to question #1
Response: Please see response to Q1.		
Electric Reliability Council of Texas, Inc.	No	If non-consequential load shedding is allowed for single contingency conditions, as discussed above, it should be based on objective critieria. As such, there is no need for the proposed stakeholder process, including the Section III instances requiring regulatory approval. As with the other stakeholder process sections, that section should be eliminated.
Response: Industry and the NERC BOT have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The SDT is now attempting to address FERC's concern expressed in their Remand Order 762 that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process, is vague, unenforceable, and not responsive to the previous Commission directives on this matter. The draft		

Organization	Yes or No	Question 4 Comment
posted for comment adds detail and specificity to the already-approved approach. The SDT does not believe it appropriate to move away from the industry and BOT approved Stakeholder Process approach. No change made. Section 3 directly addresses concerns raised by FERC contained in the remand of the TPL standard. Items 1 and 2 are included to further define and "put a box" around the situations where first Contingency Load shedding could be employed. The SDT believes that an evaluation by the ERO of the potential for adverse system impacts is needed to provide continent-wide consistency. Therefore, Section III is needed. No change made.		
San Diego Gas & Electric	No	
Public Utility District No. 1 of Snohomish County	No	
Response: Without specific comments, the SDT is unable to respond.		
Orlando Utilities Commission	Yes	Comment #1: The maximum threshold should be in the Footnote, not in the Attachment. Comment #2: I think the role identified for the Regional Entity is appropriate. Comment #3: I like the concept that regulatory approval is not required until year one. However I think either the ordering of language or the formatting needs to be changed to make it clear that the year one applies to only those that need regulatory approval. Maybe change the section to read... "Section IIIFirm Demand Interruptions under footnote 'b' that meet either or both of the criteria below are required to have approval by the applicable regulatory authority or governing body responsible for retail electric service issues. The regulatory approval is required prior to the use of that remedy in Year One of a Corrective Plan in the Planning Assessment. (Existing 1 & 2)(Existing RE Review)
Response: The maximum threshold is the last sentence of the footnote, and is also cited in Section III of the Attachment. No change made.		

Organization	Yes or No	Question 4 Comment
The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency. Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote ‘b’, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption. The SDT has modified the footnote to require regulatory authority review, rather than approval. This should help alleviate some of the concerns. An entity wishing to utilize footnote “b” should start the review process at an appropriate time so that it will be completed by the required date. Before a Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote ‘b’ if either:		
LCEC (Lee County Electric Cooperative		No comment as although we are a Firm Demand customer of another entity, we have no Firm Demand / Load customers and therefore would not perform the Stakeholder Process
CPS Energy	Yes	
Idaho Power Co.	Yes	
Nova Scotia Power	Yes	
Response: Thank you for your support.		

5. **If you have any other comments on this Standard that you haven't already mentioned above, please provide them here.**

Summary Consideration: Many commenters proposed changes to the applicable planning events for which footnote 12 applies in the new proposed TPL-001-2a standard. The SDT clarifies that the planning events for which footnote 12 are applicable were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011) in its consideration of TPL-001-2. The proposed changes are outside the scope of this project, which aims to clarify the stakeholder approval process.

Some commenters indicated confusion surrounding changes made to footnote 12 and Attachment 1 in the proposed TPL-001-2a standard in regard to the use of the term Firm Demand interruption. The SDT acknowledges that the references to Firm Demand Interruption should reference Non-Consequential Load Loss in footnote 12. The SDT has made revisions to the TPL-001-2a Footnote 12 and Attachment I to show these changes.

Some commenters continue to weigh-in on FERC's jurisdiction in regard to continuity of service to Load. FERC Order 762, beginning at Paragraph 23, discusses FERC's position on jurisdictional issues. This topic was well-vetted in the development of TPL-001-2, and FERC's subsequent NOPR and is beyond the scope/authority of this drafting team.

The following change was made due to industry comments:

Effective date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

Attachment 1 – Section I, last paragraph: An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

Attachment 1, Section III, last paragraph: Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.

Organization	Yes or No	Question 5 Comment
NorthWestern Energy (NWMT)		Comments: Footnote 12 should be added to Category P2 Single Contingency Event 2, Bus Section Fault, and to Category P2 Single Continency Event 3, Internal Breaker Fault , for EHV in the Non-Consequential Load Loss column.
Response: The planning events for which footnote 12 are applicable within the proposed TPL-001-2 standard were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011). The proposed changes are outside of the scope of this project, which aims to clarify the stakeholder approval process. No change made.		
ACES Power Member Standards Collaborators		(1) The standard needs to allow more flexibility regarding the use of planned load shed to address transmission performance issues in the planning horizon. It needs to recognize that these planned load shedding events may only be preliminary decisions for addressing problems that are several years away. If there is little chance that the planned shed load will ever be relied upon in the operating time horizon, there should be much less stringent requirements. For instance, if a PC or TP relies on planned load shed for year five of the planning horizion but year one does not utilize the planned load shed, they have four years to develop another solution. Why should great effort and resources be expended in year five when another solution will likely be developed? (2) This standard does not consider if the local regulatory body will act in time to approve the use of planned Firm Demand interruption. We believe the standard needs to consider that the Planning Coordinator and Transmission Planner may not be able to control the timelines of local regulatory agencies. As long as the PC and TP have done their part by submitting the data, they should be able to rely on the planned Firm Demand interruption until the local regulatory body acts. If the planned Firm Demand interruption is not approved, then the TP and PC should be given more time to address the transmission performance deficiency. (3) Several terms are used for the use of planned load shed. Non-consequential load loss and Firm Demand interruption are two examples. We suggest using one term consistently throughout the standard.

Organization	Yes or No	Question 5 Comment
Response: (1) For reasons similar to those raised by the commenter, the SDT limited Attachment 1 as being applicable only to planned use of Firm Demand interruption in the Near-term Planning Horizon (Years 1-5), recognizing that plans may change. The SDT believes it is appropriate to require the stakeholder approval process in the Near-term Planning Horizon. The Near-term Planning Horizon plans should become more stable over those identified on the Long-term Planning Horizon. No changes made. (2) The SDT has clarified the language concerning regulatory approval to show that review is what is actually required. Review by the regulatory authority or governing body responsible for retail electric service issues is only required in certain instance of planned Firm Demand interruption and if planned for use in Year One of the Near-Term Transmission Planning Horizon. When required, the indicated review must be obtained before it can be part of a Corrective Action Plan. Until such review, the planner would need to consider and list alternate Corrective Action Plans within its assessment. The SDT has also clarified that such reviews need only be done once, unless material changes have taken place. The SDT believes that these changes should alleviate the majority of lead-time concerns, although an entity should always build sufficient time for the process to play out into its planning cycle. (3) An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application. (4) Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption. **(5)** The terms used are appropriate since the existing FERC-approved TPL standards and the proposed TPL-001-2 (NERC Board of Trustees approved 8/4/2011) use differing terminology for the common topic (planned load shed) of both footnote 'b' (Firm Demand Interruption) and footnote 12 (Non-Consequential Load Loss). The SDT acknowledges that the reference to Firm Demand Interruption should reference Non-Consequential Load Loss. The SDT has made appropriate revisions to proposed TPL-001-2a, Attachment I.		
Independent Electricity System Operator		(1) We'd like to reiterate our support for allowing load interruption for a single contingency with sufficient review/oversight and under acceptable conditions,

Organization	Yes or No	Question 5 Comment
		including no adverse impact on the reliability of the bulk electric system. The reliability aspects (BES performance requirements) should be reviewed/approved by the Reliability Coordinator. However, issues pertaining to economics or externalities which may not be directly reliability-related are always available for review and debate by the stakeholders via the regulatory processes and subject to approval by the regulatory authority of each jurisdiction (particularly those in Canada and Mexico). (2) Furthermore, we request that Table 1 of TPL-001-3 (previous TPL-001-2 approved by NERC BOT) be corrected for EHV contingencies in P2, P4 and P5 categories to allow the same load interruption that is allowed for the related P1 contingency. Table 1 currently does not allow any load to be interrupted for an EHV single contingency if the primary circuit breakers fail to clear the fault (Category P4, “Fault plus stuck breaker”). But if load X is allowed to be interrupted for a single EHV transmission line contingency (Category P1), it should be allowed to interrupt the same load X if the primary breaker fails and the fault is cleared by other breakers. Similarly, if the same breaker has an internal fault or there is a fault on the same bus section (Category P2) or there is a failure of a relay (Category P5), which results in the loss of the same EHV transmission line, it should be allowed to interrupt the same load X. (3) We suggest that NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve them. Accordingly, we believe that the focus of the foot note ‘b’ should be that interruption of load must not adversely impact the reliability of the interconnected BES because reliability of supply to load and/or supply continuity is mandated by the jurisdictional authority. (4) We submit that the scope of NERC’s mandatory standards does not extend to assessing or setting requirements for non-jurisdictional entities, unless such facilities are necessary for the operation of the interconnected BES or have an adverse impact on its reliability. For Canadian entities there are regulatory requirements and processes under the purview of the relevant regulatory authorities that we believe are adequate. Accordingly, customer interests are protected and are not subject to

Organization	Yes or No	Question 5 Comment
		unilateral decisions of the transmission planner. In all cases, steps are taken at the planning, design, and operations stages of system development such that non-consequential Firm Demand interruption would not adversely impact the BES and the affected customer has been given the opportunity to avail themselves of other options under the transmission development rules in the relevant jurisdictions. (5) The requirements of the footnote (including attachment) will amount to a mandate to construct additional transmission which is inconsistent with Section 215 (i) (2) of the US Federal Power Act which specifically does not authorize the ERO “to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services. (6) We suggest that NERC should not include and/or address load reliability or load supply continuity requirements within the BES Reliability Standards. In Canada, these requirements and approvals are with relevant reliability or regulatory authority. If NERC feels obligated to include such requirements for load reliability issues in US, then we propose that non-jurisdictional entities must be exempted from these requirements similar to the provisions in NUC 001. (7) The proposed implementation plan conflicts with Ontario regulatory practice respecting the effective date of the standard. It is suggested that this conflict be removed by appending to the implementation plan wording, after each “applicable regulatory approval” in the Effective Dates Section A5 of both draft standards, to the following effect: “, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.”

Response:

(1) The SDT thanks you for your general support of the proposed stakeholder process. It’s anticipated that the Reliability Coordinator will be a stakeholder participant and could raise any concerns they believe are warranted. The SDT appropriately set the BES reliability approval to the Regional Entity with ERO backstop authority per FERC Order 762, Par. 55. Paragraph 55 states in part: “NERC and the Regional Entities provide both objectivity in the decision-making process as well as the necessary

Organization	Yes or No	Question 5 Comment
reliability-focused expertise." No change made. (2) The planning events for which footnote 12 is applicable within the proposed TPL-001-2 standard were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011). The proposed changes are outside of the scope of this project which aims to clarify the stakeholder approval process. No change made. (3) The proposed Attachment 1 achieves the view stated by the commenter. BES Reliability is assured by the Regional Entity and ERO where warranted. The approval by the regulatory authority or governing body responsible for retail electric service issues addresses continuity of service to end-use Load. No change made. (4) The proposed Attachment 1 process appropriately sets governance for both the ERO and Regional Entities to ensure no Adverse Reliability Impact of the BES. If existing processes are already in place to ensure end-use Loads are appropriately protected, those processes may be utilized to fulfill the Attachment I obligations. No changes made. (5) FERC Order 762, beginning at Paragraph 23 discusses the FERC's position on jurisdictional issues that are raised by the commenter. This topic was well-vetted in the development of TPL-001-2 and FERC's subsequent NOPR and is beyond the scope/authority of this drafting team. No changes made. (6) There are no current exemptions in the TPL standards, and it is not within the scope of the SDT to introduce any at this time. No change made. (7) The SDT has revised the effective date language to reflect the latest guidance received from the Standards Committee. The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.		
MISO		(1) The process described in Attachment 1 may be more suited for inclusion in the Rules of Procedure, similar to the process required for seeking BES facility exceptions. We urge the SDT to consider moving Attachment 1 into a proposed RoP instead of

Organization	Yes or No	Question 5 Comment
		stipulating it in the standard. (2) It may be more appropriate to develop a Standards process that covers the technical aspects of using a footnote 12 and leave regulatory review and approval to FERC and State agencies.
Response: (1) The SDT respectfully disagrees with the commenter. Inclusion of the Attachment 1 text within the Rules of Procedure might be appropriate for consideration if the process had wide impact on multiple NERC reliability standards. As such, since limited to use within the TPL standards, its inclusion directly within the TPL standard(s) is applicable. No changes made. **(2)** The SDT believes the Attachment 1 process strikes the appropriate balance of regulatory oversight. BES Reliability is assured by the Regional Entity and ERO where warranted by assessing any Adverse Reliability Impact. The regulatory authority or governing body responsible for retail electric service issues addresses continuity of service to end-use Load. No change made.		
Deseret Generation & Transmission Cooperative Salt River Project Los Angrles Department of Water and Power Tri-State Generation & Transmission Association, Inc. nevada power company dba nvenergy PG&E Company		: The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2.Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV in P1 is of no value. The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a

Organization	Yes or No	Question 5 Comment
		bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 3The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column.
Hydro-Quebec TransEnergie		Footnote 12 is not applied to Categories P4 and P5, which would include a EHV stuck breaker or failure of a non-redundant relay for a Multiple Contingency. The Load loss restriction for the contingencies listed in P4 and P5 is more restrictive than for the loss of a EHV double circuit line. Statistics indicate that the contingencies presented in P4 and P5 are less frequent. HQT requests that Footnote 12 should also be used for P4 and P5 contingencies for EHV. Even though considering Firm Demand interruption in planning might not be common practice, HQT agrees that the proposed Footnote 12 should maintain such a possibility.
Response: The planning events for which footnote 12 are applicable within the proposed TPL-001-2 standard were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011). The proposed changes are outside of the scope of this project, which aims to clarify the stakeholder approval process. No change made.		
Essential Power, LLC		As written, this change is complex and will be difficult to execute without additional turmoil on the planning end and offers limited clarification. Some additional issues to consider;1. Should this level of contingency allow isolation/removal of load or generation if not part of the outage? 2. Should additional generation be allowed to be removed, again considering the contingency level?
Response: 1. The binary question of applicable use was well vetted during the development of both the revised footnote ‘b’ and footnote 12. It is clear that some use, appropriately bounded, is the desire of industry and FERC. The SDT believes the proposed Attachment 1 provides the clarity sought by FERC in its remand of footnote ‘b’ and that the process is reasonable in its approach. No		

Organization	Yes or No	Question 5 Comment
changes made. 2. Generation is not addressed in footnote ‘b’. No change made.		
Public Utility District No. 1 of Snohomish County		Comments: SNPD generally disagrees with the draft process that has been developed, and notes that infrequent interruption of small amounts of non-consequential load under limited conditions that does not negatively impact a neighboring TOP is not a reliability issue. Instead it is a cost of service and customer service matter best left to the local and state regulatory bodies. The time and resources spent on this issue at the national level diverts scarse resources and attention from more important efforts that might actually benefit the reliability of the BES. SNPD supports the Pacificorp Revision of TPL-002 footnote ‘b’ and TPL-001 footnote 1 Comments- The proposed revisions will require regulatory approval for interruptions of firm demand under TPL-002 footnote b or TPL-001 footnote 12 if the voltage level of the contingency is greater than 300 kV with certain sub-conditions or if the planned interruption of firm demand under these footnotes is greater than or equal to 25 MW. The 2011 peak winter and summer loads in the Western Electricity Coordinating Council (WECC) region were 131,471 and 152,211 MW respectively. Total installed generation is 229,189 MW. There are 120,385 miles of AC transmission lines 100 kV and above, and of that total, 31,138 miles of AC transmission lines are operated at voltages above 300 kV. There are 1,744 miles of DC transmission lines.The proposed revisions would add considerable process and documentation for any interruptions, and will require regulatory approval if the interruption is greater than 25 MW. This is 0.016 percent of the WECC peak load. The planning standards already require Category B1 contingencies to be considered which result in the loss of a single generator since individual generator units range in size up to more than 1000 MW. Since these contingencies are routinely studied, it is very, very difficult to imagine that the loss of 25 MW or more of firm demand under TPL-002 footnote b or TPL-001 footnote 12 is so critical to the reliability of the BES that it deserves not only a lengthy footnote, but a two page attachment detailing a

Organization	Yes or No	Question 5 Comment
		complex and lengthy process detailing requirements public meetings, procedures for questions, specifications for documentation, and even a dispute resolution process. As this is not a BES reliability issue, any action regarding potential curtailments of local loads should occur at the local level where the cost and benefit of improvements can be properly assessed. The recent blackout that left 2.7 million customers in Southern California, Arizona and Baja California without power was not due to planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. SNPD is not aware of any regional disturbances or cascading events that were due to planned or controlled interruptions of electric supply where a single contingency occurred on a transmission system. As these proposed requirements could be removed from the Reliability Standards with little or no effect on reliability and would, if anything, increase the efficiency of the ERO compliance program, the proposed limitations on curtailment of firm demand under TPL-002 footnote b or TPL-001 footnote 12 should be removed.
Response: The feedback offered is largely aimed at FERC's jurisdictional issues in regard to continuity of service of end-use Load. FERC Order 762, beginning at Paragraph 23, discusses the FERC's position on jurisdictional issues that are raised by the commenter. This topic was well-vetted in the development of TPL-001-2 and FERC's subsequent NOPR and is beyond the scope/authority of this drafting team. No changes made. In regard to support offered for the Pacificorp proposal, we direct the commenter to view the SDT response to Pacificorp comments.		
Tacoma Power		FERC order 762 states that "to plan for the loss of firm service at the fringes of various systems would be an acceptable approach." The newly defined contingency P2.1 requiring analysis of open ended line sections should allow load shedding of the load on the line section as suggested in the FERC order.
Response: As P2.1 already includes footnote 12, the SDT is assuming that you are supporting the SDT position and thanks you for your support.		

Organization	Yes or No	Question 5 Comment
San Diego Gas & Electric		In FERC Order 762, FERC rejected NERC's footnote (b) and urged "...NERC to develop modifications responsive to the Commission's directives in Order No. 693 and our concerns set forth in this final rule." The NERC SDT has done little to address FERC's concerns and instead has resubmitted the same document with additional language. Order 693 directed NERC to develop modifications to TPL-002-0, which clarify footnote (b). As redrafted, footnote (b) does not address FERC's concerns. For example, footnote (b) continues to use the term "Firm Demand," which describes all forms of demand whether served by the faulted element or not. On the contrary, "consequential load loss" is load, which is removed as a result of a fault. Clearly, these are different concepts and the new language does not comply with FERC's directive. FERC's position has been that non-consequential load loss through load shedding shall not be allowed as an exception to TPL-002-0. Also, FERC has stated that the interruption of Firm Transmission not be allowed as an exception. But, Footnote (b) continues to say, "Curtailment of firm transfers is allowed ...". Another inconsistency. Beyond the differences between what FERC directed NERC to do and what NERC did, as written, footnote (b) would introduce "stakeholder interests" into tranmission reliability even if those interests do not promote reliability. The TPL standards identify the Planning Authority and Transmission Planner as the entities responsible for meeting the standards and makes no mention stakeholders. To meet the reliability objectives of the standard, the Planning Authority and Transmission Planner are subject to Measures and the Compliance Monitoring Process. In FERC Order 762, FERC determined "...that openness and transparency do not alone ensure bulk electric system performance criteria will be met..." and was "...not persuaded that developing technical criteria is unachievable." Although FERC does not disagree with adding a stakeholder process, clearly, they do not endorse one and prefer a technical approach to creating the exception under footnote "b".
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single		

Organization	Yes or No	Question 5 Comment
Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.		
Consolidate Edison Co. of NY, Inc.		Planned interruptions of Firm Demand in response to a Single Contingency (as directed in Footnote b of TPL-002 Table 1, is not an acceptable corrective action to mitigate reliability issues on the BES system. The Interconnected System should be designed and operated with enough transfer capacity to be able to withstand, at a minimum, a single contingency event without service interruptions to customer load. Systems must be designed and operated so that the impact of any single contingency can be mitigated by re-dispatching available system resources without the need to implement load shedding.
Response: The binary question of applicable use was well-vetted during the development of both the revised footnote 'b' and footnote 12. It is clear that some use, appropriately bounded, is the desire of industry and FERC. The SDT believes the proposed Attachment 1 provide the clarity sought by FERC in its remand of footnote 'b' and that the process is reasonable in its approach. No changes made.		
Manitoba Hydro		Please clarify if an entity must set up a stakeholder process if Firm demand interruption is not used as an element of the Corrective Action Plan. As I understand it, the footnote b in TPL 002 will be replicated in the other relevant TPL standards once it is approved. When it is included in the other TPL standards, will it be customized to each standard, or will it appear exactly the same in each standard? Footnote 12 of TPL-001 as currently drafted seems a bit disjointed or incomplete - i.e. its referring to Non Consequential Load Loss and then it refers you to an Attachment for the calculation of Firm Demand interruption without providing a connection

Organization	Yes or No	Question 5 Comment
		between the two concepts .
Response: A process would only be required if an entity allows or intends to utilize planned Load shed to meet the performance requirements for single Contingency (N-1) events. The commenter is correct that the final footnote 'b' and Attachment 1 will be replicated in the other currently-enforceable TPL standards – TPL-001, TPL-002, TPL-003 and TPL-004. The SDT acknowledges that the references to Firm Demand Interruption should reference Non-Consequential Load Loss. The SDT has made revisions to the TPL-001-2a Footnote 12 and Attachment I to show these changes.		
TVA Transmission Reliability Engineering & Controls		Please see answer to question #1. TVA beleives that only load drops of higher magnitudes go thru the Stakeholder and regulatory review.
Response: Please see response to Q1.		
BrightSource Energy, Inc. Utility System Efficiencies, Inc.		The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2.Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV inconsistent with P1.The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore

Organization	Yes or No	Question 5 Comment
		the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 2The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column. The new definition of Non-consequential Load Loss compared to the last version seems to have deleted the reference to Loads that may be lost during transient conditions due to under-frequency load shedding (UFLS), while the reference to Load Loss due to under-voltage load shedding (UVLS) is retained. As a result Load Loss due to UFLS would be part of Non-consequential Load Loss, and will not be allowed under single contingency. Because UFLS may also be triggered during transient simulations, please change the definition for Non-consequential Load Loss to read:"Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load or frequency sensitive Load, or (3) Load that is disconnected from the System by end-user equipment."It is also understood that load loss due to UVLS or UFLS or load that are disconnected from the system by customer equipment are not to be used in meeting steady state reliability requirements. Therefore, in Table 1, please change header-note "i" to read:"The response of voltage sensitive Load and Frequency sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements."
Response: 1 & 2. The SDT disagrees that the use of Footnote 'b' between P1 and P2 for EHV is inconsistent. The SDT believes that the system should be planned so that a fault on an EHV bus section or an internal fault on a non-bus-tie EHV breaker should not require planned Load loss to resolve system performance issues. The planning events for which footnote 12 is applicable within the proposed TPL-001-2 standard were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011). The proposed changes are outside of the scope of this project, which aims to clarify the stakeholder approval process. No change made. 3. The definitions have not been revised, since the standard was approved by the NERC Board of Trustees and changes to those definitions are not in the scope of this project. No change made.		

Organization	Yes or No	Question 5 Comment
California Independent System Operator		The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2.Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV in P1 is of no value.The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 3The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column. The process described in Attachment 1 may be more suited for inclusion in the Rules of Procedure, similar to the process required for seeking BES facility exceptions. We urge the SDT to consider moving Attachment 1 into a proposed RoP instead of stipulating it in the standard.

Response: 1 & 2. The SDT disagrees that the use of footnote ‘b’ between P1 and P2 for EHV is inconsistent. The SDT believes that the system should be planned so that a fault on an EHV bus section or an internal fault on a non-bus-tie EHV breaker should not require

Organization	Yes or No	Question 5 Comment
planned Load loss to resolve system performance issues. The planning events for which footnote 12 is applicable within the proposed TPL-001-2 standard were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011). The proposed changes are outside of the scope of this project, which aims to clarify the stakeholder approval process. No change made. 3. The SDT disagrees that the attachment should be moved to the NERC Rules of Procedures. Inclusion of the Attachment 1 text within the Rules of Procedure might be appropriate for consideration if the process had wide impact on multiple NERC reliability standards. As such, since limited to use within the TPL standards, its inclusion directly within the TPL standard(s) is applicable. No changes made.		
Georgia Transmission Corporation		The current draft for Requirement 5 (R5) of the NERC Standard TPL-001-3 Draft 1 reads as follows:"Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level."GTC has the following comments regarding TPL-001-3, R5:If the responsible entity has criteria for transient voltage response, along with criteria for acceptable system steady state voltage (including a pre-contingency high and low voltage limit, and a post-contingency high and low voltage limit), then having a steady state post-contingency voltage deviation criteria does not affect the reliability of the bulk electric system (BES). If the system response to a disturbance were to violate either the transient response criteria, or the steady state maximum/minimum voltage criteria, there is potential for loss of integrity of the BES. There is little to no potential for a loss of system integrity due soley to a violation of the steady state voltage deviation criteria. Therefore, Georgia Transmission Corporation requests that R5 not include a requirement to have criteria for post-Contingency voltage deviations.
Response: Requirement R5 requires the Transmission Planner and the Planning Coordinator to have established voltage criteria for their system. This set of criteria is necessary to ensure that the planners are evaluating the voltage excursions (transient and steady state) against their performance criteria. The standard requirements have not been revised since the standard was approved by the NERC Board of Trustees, and changes to those requirements are not in the scope of this project. No change made.		

Organization	Yes or No	Question 5 Comment
Salt River Project		The new definition of Non-consequential Load Loss compared to the last version seems to have deleted the reference to Loads that may be lost during transient conditions due to under-frequency load shedding (UFLS), while the reference to Load Loss due to under-voltage load shedding (UVLS) is retained. As a result Load Loss due to UFLS would be part of Non-consequential Load Loss, and will not be allowed under single contingency. Because UFLS may also be triggered during transient simulations, please change the definition for Non-consequential Load Loss to read:"Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load or frequency sensitive Load, or (3) Load that is disconnected from the System by end-user equipment."It is also understood that load loss due to UVLS or UFLS or load that are disconnected from the system by customer equipment are not to be used in meeting steady state reliability requirements. Therefore, in Table 1, please change header-note "i" to read:"The response of voltage sensitive Load and Frequency sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements."
Response: The definitions have not been revised since the standard was approved by the NERC Board of Trustees, and changes to those definitions are not in the scope of this project. No change made.		
MRO NSRF		The NSRF has concerns that over regulation of footnote "b" or "12" could cause lost opportunities for legitimate growth. An example condition would be the development of a large load in a relatively weak transmission area. Many times new large loads need open undeveloped areas to locate. Without the footnote "b" or "12" option, could an entity be forced to turn away legitimate load growth? The key being that an entity could serve the new large load under normal conditions with easy quick upgrades, but would need 5 - 7 years to construct additional transmission to meet N-1 conditions? Therefore the entity would need to turn away new growth because of over regulation on footnote "b" or "12".

Organization	Yes or No	Question 5 Comment
Response: The SDT does not believe that the proposed revision to footnote 'b' (or footnote 12) will restrict an entity's ability to serve new Load. The SDT has attempted to find a balance between being overly prescriptive and allowing entities the tools they need for planning purposes while responding to the remand from FERC. No change made.		
LCRA Transmission Services Corporation		The primary objection to Footnote 12 is twofold:1. Application to the P3 contingency. This contingency is a Category C contingency under the current NERC TPL-003 standard and allows for load shedding. Thus, the proposed standard revision is a significant and substantial increase in the reliability standard. 2. Use of the term "Firm Demand" as opposed to "Non-Consequential Load Loss." The NERC Glossary defines Firm Demand as "That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions" and Demand as "The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time." Thus interruption of Firm Demand may not result in Non-Consequential Load Loss. Therm "Firm Demand" should be replaces with "Non-Consequential Load Loss."
Response: 1. Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. 2. The SDT determined that it was appropriate to maintain the existing headers in the existing TPL standards and begin using "Non-		

Organization	Yes or No	Question 5 Comment
Consequential Load Loss" with the new TPL-001-2. No change made.		
Electric Reliability Council of Texas, Inc.		The SDT is not required to utilize the stakeholder approach by Order 762 or any other relevant FERC orders. FERC merely provided guidance as to how the rejected proposal could be improved. However, if the SDT elects to pursue an exception process, such exceptions should be based on objective criteria, and the process should be external to the NERC Reliability Standards (e.g. in the Rules of Procedure). In Order 693, FERC directed NERC to clarify footnote (b) to prohibit shedding firm load except for consequential load loss (Order 693 at PP 1773, 1794 and 1797). In a related compliance order, FERC reaffirmed its position. (130 FERC Â¶ 61,200 (March 18, 2010) at PP 8-10 (Compliance Order)) In a subsequent order, FERC clarified that its Order 693 directive did not preclude consideration of specific comments related to planning the system based on load shedding at the "fringes" of a system. (131 FERC Â¶ 61,231 (June 11, 2010) at P 21 (Clarification Order)) FERC held that regional variances for case-specific circumstances or a case-specific exception process to plan for the loss of firm service "at the fringes of various systems" would be acceptable. (131 FERC Â¶ 61,231 (June 11, 2010) at P 21 (Clarification Order)) However, FERC also stated that it viewed the basis for such exceptions as economic, not reliability, with the justification being that it was not economic to invest in the bulk electric system to serve all non-consequential load customers under some single contingency conditions. (Order 693 at P 1792) FERC made clear that any such regional differences or case specific exception processes cannot reflect the lowest common denominator, and, they must be technically justified, and such justification must be strong. (Clarification Order at P 21. See also Order 693 at P 1794) This is consistent with FERC's position that this is a matter of "fundamental issue of transmission service". (Order 693 at P 1793) In recognizing that meeting firm demand under single contingency conditions is fundamental to transmission service, FERC noted that NERC's definition of firm transmission service is the "highest quality (priority) service offered to customers...that anticipates no planned interruption." (Order 693 at P 1793)Against this background, NERC filed revisions to footnote b that allowed transmission plans to shed non-consequential load under single contingency

Organization	Yes or No	Question 5 Comment
		conditions, provided appropriate process applied to such planning determinations/outcomes. In Order No. 762, (139 FERC Â¶ 61,060 (April 19, 2012)) FERC rejected the approach proposed by NERC and provided guidance on acceptable approaches to footnote b. However, FERC did not endorse or mandate any particular approach. Rather, it merely urged "NERC to develop in a timely manner an appropriate modification that is responsive to the Commission's directives in Order No. 693 and our concerns set forth in this Final Rule." (Order 762 at P21) FERC stated that in order for any such proposal to have merit, it must be technically justified and must not reflect the lowest common denominator.As discussed, the proposed stakeholder approach is not appropriate for NERC Reliability Standards. The SDT should abandon that approach and consider simple revisions to footnote b that reference a case by case exception process based on objective criteria that is external to the NERC Reliability Standards (e.g. Rules of Procedure). Alterantively, it should develop revisions to the continent-wide standards that clarify that non-consequential load shedding is not generally permitted for single contingency conditions, but, consistent with FERC's orders, exceptions could be established pursuant to regional rules based on the need/appropriateness in a particular region. Consistent with the above discussion, if the SDT elects to pursue revisions that accommodate shedding non-consequential load in transmission planning for single contingency conditions, it should abandon the stakeholder process approach. The establishment of exceptions is better suited for regional rules or pursuant to a process outside of the reliability standards - e.g. via the Rules of Procedure, because such a process is not suited for a continent-wide reliability standard. Regardless of whether the issue is addressed via an external process, or left to regional variances, this issue needs to be addressed in a relatively timely manner because the uncertainty is affecting planning processes.

Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission

Organization	Yes or No	Question 5 Comment
remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.		
Southern Company		The use of load dropping should be limited to being only an interim solution while a project is being completed and nothing else can be done.
Response: An entity can choose to restrict the use of footnote 'b' to an interim solution but the SDT believes that there are instances where a long term use (permanent or near-permanent) of footnote 'b' may be appropriate. For example, the amount of Load involved versus the probability of occurrence might dictate that a long term use is in the best overall interests of the customers. No change made.		
Arizona Public Service Company		This process is too prescriptive and must be simplified.
Response: Without specific comments, the SDT is unable to respond.		
Ameren		To clarify, the Stakeholder Process should not be initiated until the amount of Firm Demand expected to be interrupted by the TP or PC as mitigation reaches a threshold of 10 MW. However, at that point, the Stakeholder Process should commence, but not without incorporating the need to obtain approvals from the stakeholders, regardless of the amount of load to be interrupted beyond the 10 MW threshold level, and regardless of the voltage level of the transmission elements involved in the contingency event(s). As drafted, the Stakeholder Process appears to be silent on receiving approvals to drop load of less than 25 MW. We believe that this is an invitation to trouble for the industry. For example, if a TP or PC were to have a contingency for which the mitigation is to interrupt 15 MW of Firm Demand, all the stakeholders would be called in just to inform them that their load is subject to

Organization	Yes or No	Question 5 Comment
		interruption, but their displeasure is not relevant, because the 25 MW interruption level had not been reached, and approval is not required. Thus, we believe that as drafted Stakeholder Process needs some additional work before we could support it.
Response: The stakeholder process is required anytime that Load is planned to be interrupted pursuant to footnote 'b'. Approval by the applicable regulatory authority or governing body responsible for retail electric service issues is required for planned interruptions greater than 25 MW. The SDT believes that this level is the appropriate balance to protect the interests of the customers without being unduly burdensome. No change made.		
Southwest Power Pool Reliability Standards Development Team		We agree the distinction between consequential and non- consequential is necessary. We don't agree that you should plan for non-consequential load loss/shed. You shouldn't have to interrupt firm service for n-1 contingency.
Response: The SDT believes that there are instances where use of footnote 'b' may be appropriate. For example, the amount of Load involved versus the probability of occurrence might dictate that a use of footnote 'b' is in the best overall interests of the customers. No change made.		
Nova Scotia Power		With regard to the application of Footnote 12 in TPL-001-3, the footnote is only applied to the contingencies in Table 1 involving loss of a Single Line with a 3 phase fault (P1) or opening of a line without a fault (P2-1). These are higher probability events relative to other types of contingencies, and Footnote 12 allows for loss of load for these events, but does not allow for loss of load for lower probability events that have the same results, such as P2-2 and P2-3. Take for example a single radial 345kV line feeding a small radial portion of the system, with a line end transformer and breaker between the transformer and the line. Application of Footnote 12 to only a P1 event (loss of the line on its own, or loss of the transformer on its own) but loss of the breaker between the line and the transformer would not be allowed, even though the result would be the same. Without applying footnote 12 to category P2-2 and P2-3 would mean that Footnote 12 is rendered moot (can never be used). Similarly, Footnote 12 should be applied to P4 and P5, essentially wherever Footnote 9 is applied, otherwise Footnote 12 can never be applied.

Organization	Yes or No	Question 5 Comment
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. The SDT believes that the system should be planned so that a fault on an EHV bus section (or an internal fault on a non-bus-tie EHV breaker) should not require planned Load loss to resolve system performance issues. No change made.		
Northeast Power Coordinating Council		NPCC reviewed the posted documents, and has no comments for this posting.

END OF REPORT

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project Revision of TPL-002 footnote 'b' and TPL-001 footnote 12

The Project 2010-11 Drafting Team thanks all commenters who submitted comments on the proposed standards, TPL-002-1c and TPL-001-2a. The standards were posted for a 45-day public comment period from October 5, 2012 through November 19, 2012 with the initial ballot period from November 9, 2012 to November 19, 2012. There were 61 sets of comments, including comments from approximately 149 different people from approximately 112 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

Summary: The drafting team made the following revisions in response to comments:

TPL-002-1c: footnote b - ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load.

TPL-001-2a: footnote 12 **-** An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following ~~Contingency~~ planning events.

TPL-001-2a: footnote 12 - However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1.

Section II, Bullet 2b. ~~Assessment~~ An explanation of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community

Section II, Bullet #5. Future plans to ~~mitigate~~ alleviate the need for Firm Demand interruption under footnote 'b'

Section III, first paragraph: Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ~~assure~~ ensure that the applicable regulatory ~~authority~~ authorities or governing ~~body~~bodies responsible for retail electric service issues do~~es~~ not object to the use of Firm Demand interruption under footnote 'b' if either:

Section III, last paragraph: Once assurance has been received that the applicable regulatory ~~authority~~ authorities or governing ~~body~~bodies responsible for retail electric service issues do~~es~~ not object to the use of Firm Demand interruption under footnote ‘b’, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption.

A number of respondents continue to question the legality of the proposed standards. The general line of thought in those comments is that NERC is imposing itself into the local planning process in violation of existing statutes. The SDT does not believe that to be the case and has responded accordingly to those commenters.

Many commenters questioned the use of a stakeholder process at all. Those commenters expressed the opinion that the FERC Order did not mandate the use of the stakeholder process. The SDT used the Board of Trustees approved standard as a starting point for this draft. FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach.

In addition, many commenters chose to question already approved facets of the proposed TPL-001-2a standard. These commenters are questioning the application (or non-application) of footnote 12 for various planning events. TPL-001-2 was previously approved by the industry and the NERC Board of Trustees. The SAR for this project took that approval as the starting point for the specific discussion of footnote ‘b’/12 and does not allow for review of previously approved applications of the footnote.

The SDT is requesting that the project be moved to a successive ballot.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

NERC

The Industry Segments are:

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Christina Koncz	PSEG Power LLC	NPCC	5
10.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

11.	Michael Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec Transenergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Ben Wu	Orange and Rockland Utilities	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2

				1	2	3	4	5	6	7	8	9	10
2.	Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Team	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	Robert Rhodes	Southwest Power Pool	SPP	NA
3.	John Allen	City utilities of springfield	SPP	1, 4
4.	Don Taylor	Westar Energy	SPP	1, 3, 5, 6
5.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
3.	Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.				
3.	TOM BREENE	WPS	MRO	3, 4, 5, 6
4.	JODI JENSON	WAPA	MRO	1, 6
5.	KEN GOLDSMITH	ALTW	MRO	4
6.	ALICE IRELAND	XCEL	MRO	1, 3, 5, 6
7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9.	JOE DEPOOTER	MGE	MRO	3, 4, 5, 6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	1, 3, 5, 6
12.	MARIE KNOX	MISO	MRO	2
13.	LEE KITTELSON	OTP	MRO	1, 3, 5
14.	SCOTT BOS	MPW	MRO	1, 3, 5, 6
15.	TONY EDDLEMAN	NPPD	MRO	1, 3, 5
16.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17.	DAN INMAN	MPC	MRO	1, 3, 5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	paul haase	Seattle City Light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	pawel krupa	seattle city light	WECC	1
2.	dana wheelock	seattle city light	WECC	3
3.	hao li	seattle city light	WECC	4
4.	mike haynes	seattle city light	WECC	5
5.	dennis sismaet	seattle city light	WECC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Greg Rowland	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3
3.	Dale Goodwine	Duke Energy	SERC	5
4.	Greg Cecil	Duke Energy	RFC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chuck Matthews	Transmission Planning	WECC	1
2.	Berhanu Tesema	Transmission Planning	WECC	1
3.	Melvin Rodrigues	Transmission Planning	WECC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Chris Pink	Tri-State G&T	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chris Pink			
2.	Mark Stein			
3.	Janelle Gill			

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

4.	Bill Middaugh

8.	Group	Jim Kelley	SERC EC Planning Standards Subcommittee	X				X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Co	SERC	1
2.	Charles Long	Entergy Services	SERC	1
3.	Edin Habibovich	Entergy Services	SERC	1
4.	James Manning	NC Electric Membership Corp.	SERC	1
5.	Bob Jones	Southern Company Services	SERC	1

9.	Group	Scott Miller	MEAG Power	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Steve Grego	MEAG Power	SERC	5
2.	Steve Jackson	MEAG Power	SERC	3
3.	Danny Dees	MEAG Power	SERC	1

10.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Utility Service	FRCC	3
8.	Stan Rzad	Keys Energy Services	FRCC	1

11.	Group	David Dockery - NERC Realiability Compliance Coordinator	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

5. N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6. Sho-Me Power Electric Cooperative		SERC	1, 3

				1	2	3	4	5	6	7	8	9	10
12.	Group	Michael Jones	National Grid	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. Michael Schiavone	Niagara Mohawk (A National Grid Company)	NPCC	3

				1	2	3	4	5	6	7	8	9	10
13.	Group	John Allen	Iberdrola USA	X									

Additional Member	Additional Organization	Region	Segment Selection
1. Joseph Turano	Central Maine Power	NPCC	1
2. Raymond Kinney	New York State Electric & Gas	NPCC	1

				1	2	3	4	5	6	7	8	9	10
14.	Group	Ben Engelby	ACES Power Marketing Standards Collaborators						X				

Additional Member	Additional Organization	Region	Segment Selection
1. Megan Wagner	Sunflower Electric Power Corporation	SPP	1
2. Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
3. Amber Anderson	East Kentucky Power Cooperative	SERC	1, 3, 5
4. John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
5. Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
6. Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1, 3, 4, 5

				1	2	3	4	5	6	7	8	9	10
15.	Individual	Tim Ponseti, VP	TVA Transmission Reliability Engineering and Controls	X								X	
16.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
17.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
18.	Individual	Brandy A. Dunn	Western Area Power Administration	X					X				
19.	Individual	Holly Rachel Smith, Assistant General Counsel	National Association of Regulatory Utility Commissioners									X	
20.	Individual	Thad Ness	American Electric Power	X		X		X	X				
21.	Individual	Kenn Backholm	Public Utility District No.1 of Snohomish County	X		X	X	X	X			X	

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
22.	Individual	Travis Metcalfe	Tacoma Power	X		X	X	X	X				
23.	Individual	Steven R. Wallace	Seminole Electric Cooperative, Inc.			X	X	X	X				
24.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
25.	Individual	James Tucker	Deseret Generation & Transmission	X				X					
26.	Individual	Melissa Kurtz	USACE					X					
27.	Individual	Chris Pink	Tri-State Generation & Transmission Association	X									
28.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
29.	Individual	John Collins	Platte River Power Authority	X		X		X	X				
30.	Individual	Don Jones	Texas Reliability Entity										X
31.	Individual	Kirit Shah	Ameren	X		X		X	X				
32.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
33.	Individual	David Kiguel	Hydro One Networks Inc.	X		X							
34.	Individual	Martyn Turner	LCRA Transmission Service Corporation	X									
35.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X	X				
36.	Individual	Patricia Robertson	BC Hydro and Power Authority	X	X	X		X					
37.	Individual	Terry Harbour	MidAmerican Energy Company	X		X		X	X				
38.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X					
39.	Individual	Jason Marshall	New England States Committee on Electricity (NESCOE)										
40.	Individual	Frederick R Plett	Massachusetts Attorney General								X		
41.	Individual	Richard Vine	California Independent System Operator		X								
42.	Individual	Randy MacDonald	NB Power Transmission	X									
43.	Individual	Laurie Williams	Public Service Company of New Mexico	X		X							
44.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
45.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
46.	Individual	Donald Weaver	NBSO		X								
47.	Individual	Milorad Papic	Idaho Power Company	X		X							
48.	Individual	Jack Stamper	Clark Public Utilities	X									
49.	Individual	Tom Hanzlik	SCE&G	X		X		X	X				
50.	Individual	Kathleen Goodman	ISO New England		X								
51.	Individual	Larry Watt	Lakeland Electric	X									
52.	Individual	Chantal Mazza	Hydro QuÃ©bec TransÃ‰nergie	X									
53.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
54.	Individual	Mark Westendorf	Midwest Independent Transmission System Operator, Inc.		X								
55.	Individual	Dan Inman	Minnkota Power Cooperative	X									
56.	Individual	Bob Casey	Georgia Transmission Corp	X									
57.	Individual	Michael Falvo	Independent Electricity System Operator		X								
58.	Individual	Richard Bachmeier	Gainesville Regional Utilities	X									
59.	Individual	Spencer Tacke	Modesto Irrigation District				X						
60.	Individual	Jason Weiers	Otter Tail Power Company	X		X		X					
61.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The SDT thanks you for your participation. Your support of comments from another organization has been noted.

Organization	Supporting Comments of "Entity Name"
Seattle City Light	Puget Sound Energy
MEAG Power	Snohomish County Public Utility District
Associated Electric Cooperative, Inc. - JRO00088	SERC EC Planning Standard Subcommittee
USACE	MRO NSRF
MidAmerican Energy Company	MidAmerican supports the NSRF comments
City of Austin dba Austin Energy	Tacoma Power and Snohomish P.U.D.
South Carolina Electric and Gas	South Carolina Electric and Gas - SCE&G
Clark Public Utilities	Snohomish County PUD and Tacoma Power.
Lakeland Electric	FMPA

Organization	Supporting Comments of “Entity Name”
Gainesville Regional Utilities	FMPA - Florida Municipal Power Agency
Otter Tail Power Company	Minnkota Power Cooperative

1. **Do you agree with the text in the body of the footnote including the maximum capacity threshold? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. For the maximum capacity item, please supply any technical rationale for your comment along with limiting conditions and any current criteria in use at your entity.**

Summary Consideration: The majority of the comments received for this question were handled with explanations of the SDT intent or clarifications of the constraints under which the SDT was working. There were a number of comments however concerning the justification of the threshold values. The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. DOE and other thresholds can be a point of reference or sanity check but in and of themselves are not sufficient for setting a threshold in this matter. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach.

There were several comments regarding the application of footnote 12 within Table 1 of proposed TPL-001-2a. Such discussion is out of scope for this project as defined in the Standards Authorization Request (SAR). TPL-001-2 has been approved by the industry through the standards development process and by the NERC Board of Trustees. Nothing in this project affects where footnote 12 is applied within Table 1. The only change being proposed is to the details of how to utilize footnote 12 as shown in the proposed Attachment 1.

The following clarifications to language were made due to comments received:

TPL-002-1c: footnote b) ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load.

TPL-001-2a: footnote 12 **-** An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following ~~Contingency~~ planning events.

TPL-001-2a: footnote 12 - However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1.

Organization	Yes or No	Question 1 Comment

Organization	Yes or No	Question 1 Comment
MRO NSRF USACE	No	(1) Change the wording at the end of the first sentence from "following Contingency events" to "following Contingency events and Contingency events during the planned (maintenance) outage of any bulk electric equipment)". This would remind Transmission Planners and Planning Coordinators to include the consideration of planned outages at demand levels for which the outage would be performed. (2) Raise the maximum load dropping threshold for the footnote from 75 MW to 100 MW. A 100 MW threshold is reasonable because the DOE uses the intentional dropping of more than 100 MW as one of the thresholds for determininge when enough load is dropped to justify a formal system event analysis. (3) Add a sentence at the end of the footnote to read, "This footnote does not apply to any load that is not NERC registered (e.g. load that does not meet the greater than 25 MW NERC registration criterion). (4) If a portion of the non-consequential load loss used to mitigate a contingency is controllable by a demand side load management system, can it be excluded from the "Firm Demand interruption" in TPL-002-1c Table I footnote 'b' and/or "Non-Consequential Load Loss" in TPL-001-2a Table 1 footnote 12? Does it have to be curtailed on a pre-contingent basis in order to be excluded from the non-consequential load total, or can it be excluded even if the curtailment happens through action of the UVLS? Does this load count towards the 25 MW and 75 MW thresholds? RECOMMENDATION: When describing "interruption of firm demand" or "non-consequential load loss" in footnote 'b' add the language "not counting load shed on a pre-contingent basis". This would be added to the last sentence of footnote 'b' if it indeed should not be counted towards the 75 MW threshold. Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-

Organization	Yes or No	Question 1 Comment
		2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion. (5) If multiple companies own portions of the non-consequential load loss a used to mitigate a contingency at a single substation does each company's load portion count towards the 25 MW and 75 MW thresholds or does the total load at the substation count? For example, 100% of the load at a substation is set to trip with automatic UVLS. Company A, B, and C own load amounts X, Y, and Z at the substation. Is the amount of load counted towards the 25 MW and 75 MW thresholds X+Y+Z, or is each counted separately? RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote 'b' could read "In no case can the planned Firm Demand interruption from under footnote 'b' exceed 75 MW from one entity." Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion.

Response: (1) The SDT intended the first sentence to be a fundamental statement of planning principle and thus believes that the suggested wording is redundant and therefore not required. Consideration of planned outages at demand levels for which the outage is performed is covered in proposed TPL-001-2a, Requirement R1 where it is stated that models must represent actual System conditions as well as in Requirement R2, Part 2.1.3 which clearly states that analysis is to be done when known outages are scheduled. No change made.

(2) The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. DOE thresholds can be a point of reference or sanity check but in and of themselves are not sufficient for setting a threshold in this matter. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made.

(3) Load that is served from the entity's transmission system is considered as applicable Load in this standard regardless of the

Organization	Yes or No	Question 1 Comment
underlying registration situation. No change made. (4) Proposed TPL-002-1c states in the footnote that: "It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or *Demand-Side Management Load*" (emphasis added). This makes it clear that Demand-Side Management Load is not to be considered as Non-Consequential Load. In proposed TPL-001-2a, the proposed definition of Non-Consequential Load includes the term 'Interruptible Load' which as defined in the NERC Glossary includes demand to be curtailed that the end-use customer makes available through contract or agreement. Thus, the concept is covered in proposed TPL-001-2a as well. However, upon reviewing the comments, the SDT has seen that Demand that is not included as Firm Demand for footnote 'b' could be clarified as shown below. TPL-002-1c: footnote b) - ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load. (5) "Ownership" of the Non-Consequential Load Loss is not a relevant factor; all thresholds mentioned in the footnote are related to the total Non-Consequential Load Loss. No change made.		
ACES Power Marketing Standards Collaborators	No	(1) We disagree with placing an upper limit on the amount of firm load shed. Conceptually, it seems like a good idea but we do not believe that such a threshold could ever consider all of the potential issues that could arise and would cause the need to plan to shed firm load. This is especially true considering that the SAR clarifies that the upper threshold will be based on the existing planned load shedding values. Future issues cannot be considered by the information contained in the data request. Consider a situation in which a new transmission line was included in Planning Assessment but cannot be built because right of ways cannot be obtained. Should an upper limit be placed on planned load shed in such a situation? (2) We disagree with the threshold of 75 MW. In Order No. 762, the Commission discussed the "blend concept," where it "envisioned the planner would consider up to 100 MW of planned Firm Demand interruption along with other options to resolve the system performance

Organization	Yes or No	Question 1 Comment
		criteria violation and submit its documentation and explanation to the entity deciding whether the planned load shed is acceptable." (emphasis added) Even the Commission envisioned using higher thresholds. Furthermore, the data appears to show that one instance of Non-Consequential Load Loss would be immediately out of compliance because it is actual 75.2 MW not 75 MW. If the upper threshold is too close to 75 MW, any load growth might also compel the instance to be disqualified. If the SDT plans to keep the upper limit, we suggest increasing the amount to at least 100 MW.
Response: (1) The SDT understands the problematic nature of future considerations in setting threshold values. However, the SDT believes it is unrealistic to consider the allowable usage of footnote 'b' in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. No change made. (2) The SDT believes that the threshold selected is consistent with the data supplied in the data request within reasonable limits. Increasing the threshold to 100 MW is not consistent with the data supplied and the SDT believes that such an action would be viewed as a non-acceptable least common denominator approach. No change made.		
Minnkota Power Cooperative Otter Tail Power Company	No	1. MPC QUESTION: If a portion of the non-consequential load loss used to mitigate a contingency is controllable by a demand side load management system, can it be excluded from the "Firm Demand interruption" in TPL-002-1c Table I footnote 'b' and/or "Non-Consequential Load Loss" in TPL-001-2a Table 1 footnote 12? a. Would this load count towards the 25 MW and 75 MW thresholds? b. Would it have to be curtailed on a pre-contingent basis in order to be excluded from the non-consequential load total, or can it be excluded even if the curtailment happens through action of the UVLS? c. RECOMMENDATION: When describing "interruption of firm demand" or "non-consequential load loss" in footnote 'b' add the language "not counting load shed on a pre-contingent basis". This would be added to the

Organization	Yes or No	Question 1 Comment
		last sentence of footnote ‘b’ if it indeed should not be counted towards the 75 MW threshold. Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion. 2. MPC QUESTION: If multiple companies own portions of the non-consequential load loss used to mitigate a contingency at a single substation, does each company’s load count towards the 25 MW and 75 MW thresholds or does the total load at the substation count? a. EXAMPLE: 100% of the load at a substation is set to trip with automatic UVLS. Company A, B, and C own load amounts X, Y, and Z at the substation. i. Is the amount of load counted towards the 25 MW and 75 MW thresholds X+Y+Z, or is each counted separately? b. RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote ‘b’ could read “In no case can the planned Firm Demand interruption under footnote ‘b’ exceed 75 MW from one entity.” Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion.

Response: (1) Proposed TPL-002-1c states in the footnote that: “It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or *Demand-Side Management Load*” (emphasis added). This makes it clear that Demand-Side Management Load is not to be considered as Non-Consequential Load. In proposed TPL-001-2a, the proposed definition of Non-Consequential Load includes the term ‘Interruptible Load’ which as defined in the NERC Glossary includes demand to be curtailed that the end-use customer makes available through contract or agreement. Thus, the concept is covered in proposed TPL-001-2a as well. However, upon reviewing the comments, the SDT has seen that Demand that is not included as Firm Demand for footnote ‘b’ could be clarified as shown below.

TPL-002-1c: footnote b) - ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm

Organization	Yes or No	Question 1 Comment
Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load. (2) "Ownership" of the Non-Consequential Load Loss is not a relevant factor; all thresholds mentioned in the footnote are related to the total Non-Consequential Load Loss. No change made.		
Iberdrola USA	No	"Contingency events" should be replaced by "Planning Events." Why would load shedding be limited only for certain circumstances in the Near-Term Transmission Planning Horizon? The Near Term is likely the period when the least can be done to avoid load shedding due to the time required for permitting and construction of facilities. A maximum capacity threshold is reasonable, whether 75 MW or a lower value.
Response: The SDT agrees that 'Contingency events' should be replaced by 'planning events' in proposed TPL-001-2a where the terminology in the performance tables uses 'planning' instead of 'Contingency'. However, such a change is not warranted in proposed TPL-002-1c where the 'planning' terminology was never used. TPL-001-2a: footnote 12 - An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following ~~Contingency~~ planning events. Footnote 'b' is not limited to the Near-Term Transmission Planning Horizon since the footnote recognizes that Firm Demand can be interrupted throughout the entire planning horizon. No change made. Thank you for your support.		
Massachusetts Attorney General	No	Although I voted for this Footnote, I do have concerns. 1) There is no reliability benefit to the 75MVA threshold limit. There should be no limit in the standard - it should be between stakeholders to decide that limit, not nationally imposed. 2) Any such agreement to consider non-consequential losses should have no impact to the BES especially when maintained in a confined boundary.

Organization	Yes or No	Question 1 Comment
		3) This takes away local decision making of PUC/ Local Board decision making; 4) FERC's concern that a few entities would disguise the "stakeholder" process to shed load is unfounded and should not be applied on a continent-wide basis. FERC is trying to impose tighter standards than the industry wants.
Response: (1) The SDT believes it is unrealistic to consider the allowable usage of footnote 'b' in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. No change made. (2) The SDT agrees that it normally should not have an impact. However, the purpose of the footnote is to ensure that it will not have an impact. No change made. (3) The SDT disagrees. The PUC/Local Board would typically be part of the "applicable regulatory authorities or governing bodies responsible for retail electric service issues" shown in Attachment 1, Section I, Bullet 1. The same body would be expected to be the entity involved in Attachment 1, Section III. Therefore, the PUC/Local Board would be a primary participant in the proposed process. No change made. (4) The conditions placed on the stakeholder process will provide consistency in the application of footnote 'b' on a continent-wide basis. No change made.		
Xcel Energy	No	Although the maximum capacity value is used for planning purposes, how does this correlate with operational standards/issues that may require that value be greater. The planning studies look at very specific seasonal conditions on the system and may not necessarily look at all the states of the transmission system during the normal business day. If an operational event requiring a greater value of Non-Consequential Load Loss (NCLL) is executed and the specific outage was not considered in a planning study, how will this affect compliance with the planning standard. There was no technical rationale by the SDT for selecting the maximum value, thus a limit should not be set and should be left as a general

Organization	Yes or No	Question 1 Comment
		discussion issue in the Stakeholder Process due to the many unforeseen issues that may arise.
Response: The commenter correctly points out that this is a planning standard. Operational standards have their own sets of requirements. The proposed requirements for TPL-001-2a state that models utilized must reflect System conditions anticipated for the period in question. If the planner has done this, there should be no question as to whether they are fulfilling the requirements of the standard. No change made. The SDT believes it is unrealistic to consider the allowable usage of footnote 'b' in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. The limit selected was derived from the data received for the data request. Use of actual data is the technical rationale in the selection of the threshold. No change made.		
Electric Reliability Council of Texas, Inc.	No	As an initial matter, ERCOT does not believe the planning process should allow for nonconsequential load shedding under single contingency conditions. Accordingly, ERCOT takes no position on the proposed maximum load shedding amount. Even though the NERC BoT approved the Stakeholder Process, ERCOT does not believe that the Stakeholder Process should be included as an Attachment to a footnote to a reliability standard. Also, there is an inconsistency in the terminology used in the footnotes relative to the load shed - firm demand and non-consequential load are both used. Non-consequential load is the correct term and the language should be consistent. Although it is ERCOT's position that non-consequential load should not be allowed to be shed under single contingency conditions from a planning perspective, if the SDT elects to retain a vehicle for such exceptions, it should establish objective, reliability based criteria that lend themselves to inclusion in a reliability standard. This is consistent with the general approach for reliability standards, which prescribe the "what", not the

Organization	Yes or No	Question 1 Comment
		"how". If the exceptions are based on objective criteria that are known upfront, and those criteria reflect appropriate reliability based technical justifications, then the risk of unwarranted exceptions to the general prohibition due to misuse of the exception process is mitigated. Furthermore, the exception process should be external to the NERC Reliability Standards (e.g. in the Rules of Procedure), which should merely reference authorized exceptions granted pursuant to that process. With respect to the stakeholder process, in no case should a reliability standard mandate a stakeholder process in any respect, procedural or substantive. In ISO/RTO regions, stakeholder processes fall within ISO/RTO governance matters. These issues are beyond the purview of NERC Reliability Standards. In other regions, although the relevant functional entities do not have stakeholder processes analogous to ISOs/RTOs, any relevant processes are similarly beyond the scope of the reliability standards.Accordingly, the SDT should eliminate all revisions related to the establishment of a stakeholder process. As discussed in response to question 5, FERC is not requiring this approach, but rather has only provided guidance with respect to ways to possibly bring the prior proposal in line with applicable regulatory approval standards for reliability standards. Additionally, as a general matter, substantive reliability standards requirements should not be imbedded within a footnote to a requirement. In this case, not only is there a substantive requirement imbedded in the footnote, there is also a substantial attachment (which must become part of the enforceable standard requirements}... and, to make it worse, the attachment is an attachment to the footnote, rather than an attachment to and referred to by a reliability standard requirement.

Response: ERCOT is free to adopt a position of not allowing Non-Consequential Load shed in its reliability footprint. An entity can

Organization	Yes or No	Question 1 Comment
always do more than the requirements stated. No change made. The SDT used the Board of Trustees approved standard as a starting point for this draft. FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. The use of footnotes and attachments is an acceptable mechanism for use in Reliability Standards and both mechanisms have been used before. No change made. The SDT believes that the terminology is consistent. Non-Consequential Load is a newly defined term that only applies to proposed TPL-001-2a. It is not appropriate to use this terminology in proposed TPL-002-1c which predates proposed TPL-001-2a. No change made. The SDT has set up criteria for consideration in the potential usage of footnote ‘b’ for planning purposes in Attachment 1, Section II, Bullets 1 through 8. The criteria described are objective. The process describes what must be done to allow for the usage of footnote ‘b’ in the planning process. No change made. The SDT used the Board of Trustees approved standard as a starting point for this draft. FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. If the ISO/RTO has an existing process that meets the requirements, it is free to use such process as stated in Attachment 1, Section I. No change made. Footnotes and attachments are acceptable mechanisms for use in Reliability Standards and both mechanisms have been used before. No change made.		
National Association of Regulatory Utility Commissioners	No	As NARUC stated plainly in its Comments filed in FERC Docket No. RM11-18 (Dec. 20, 2011), “not only does the law require that the States maintain authority over distribution level reliability, States are in the best position to guide load shedding so that it has the least negative impact on the State’s customers and the operation of the local distribution system.” Id at p. 4. Given the twin responsibilities of FERC to maintain bulk system reliability and the states to ensure reliable and affordable service to retail load, NARUC supports the portion of the standard that requires notification and consultation with state and local regulators. However,

Organization	Yes or No	Question 1 Comment
		the maximum capacity threshold (set at 75 MW) is problematic. In this instance, it appears that the 75 MW maximum capacity threshold is merely a reflection of antidotal information from five data request responders and as such is not technically justified. NARUC is not poised to offer an alternative; given that the state/local regulator is consulted in this process, the maximum capacity threshold should just be dropped. States should be able to authorize an 80 MW exception, or whatever level is reasonable, under specific circumstances if local economics and reliability warrant it.
Response: The data request is not anecdotal information. All of the Transmission Planners in the continental United States supplied their data in response to the data request. The SDT believes it is unrealistic to consider the allowable usage of footnote 'b' in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. Given the participation of appropriate regulatory bodies in both Sections I and III, the SDT believes that the current threshold is the best possible solution. No change made.		
American Transmission Company	No	ATC recommends the following alternative language for both Footnote 'b' (Table 1 in TPL-002-1c [page 6]) and Footnote '12' (Table 1 in TPL-001-2a [page 14]:(1) Change the wording at the end of the first sentence from "following Contingency events" to "following Contingency events for the prior condition of all equipment in service or during the planned (maintenance) outage of any bulk electric system equipment". This would remind Transmission Planners and Planning Coordinators to include the consideration of planned outages at demand levels for which the outage would be performed. (2) In the last sentence of the footnote, raise the maximum load dropping threshold for the footnote from 75 MW to 100 MW. A 100 MW threshold is reasonable because the DOE uses the intentional dropping of more than 100 MW as one of the thresholds for determining when enough load is dropped to justify a formal system event analysis.

Organization	Yes or No	Question 1 Comment
		(3) Add a sentence at the end of the footnote to read, “This footnote does not apply to any load that is not NERC registered (e.g. load that does not meet the greater than 25 MW NERC registration criterion).
Response: (1) Consideration of planned outages at demand levels for which the outage is performed is covered in proposed TPL-001-2a, Requirement R1 where it is stated that models must represent actual System conditions as well as in Requirement R2, Part 2.1.3 which states that analysis is to be done when known outages are scheduled. No change made. (2) The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote ‘b’ by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote ‘b’. DOE thresholds can be a point of reference or sanity check but in and of themselves are not sufficient for setting a threshold in this matter. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a least common denominator approach and would thus be rejected. No change made. (3) Load that is served from the entity’s transmission system is considered as applicable Load in this standard regardless of the underlying registration situation. No change made.		
Hydro QuÃ©bec TransÃ‰nergie	No	Dropping load in the general sense should not be endorsed, but it is recognized that there are special situations where it cannot be avoided. Provided there is no widespread, adverse effect on the reliability of the interconnected BES, the effect of a firm demand interruption on customers is under the purview of the applicable regulatory authority that is responsible for local transmission and retail service over the load to be curtailed, and the TPL standard should not put a limit at 75 MW.
Manitoba Hydro	No	Given that it is deemed that a stakeholder procress is required, there is no rationale for a maximum level. The stakeholders are in the best position to judge the appropriate level of allowable curtailment.
Response: The SDT believes it is unrealistic to consider the allowable usage of footnote ‘b’ in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. No		

Organization	Yes or No	Question 1 Comment
change made.		
Florida Municipal Power Agency Lakeland Electric Gainesville Regional Utilities	No	FMPA has two issues:1. What is the technical justification for 75 MW? There is no other metric in use similar to it. FMPA believes that, if the stakeholder process reveals that the stakeholders are willing to accept decreased service continuity to save money on their electric bills, why should that be limited to 75 MW which has nothing to do with BES reliability. BES reliability will not be impacted until load shedding gets near to the largest single loss of source contingency in relation to supply / demand mismatch. Other standards have chosen the low value of 300 MW as indicative, (e.g., CIP v5 for UFLS, EOP-004 for disturbance reporting); hence, FMPA recommends that the maximum amount of load shedding be 300 MW. 2. The footnote should also address a process whereby the transmission customer agrees to conditional firm service if the Transmission Planner / Transmission Service Provider (TSP) plans on curtailing firm service to that customer following a single contingency. The TSP should not be able to unilaterally degrade service from a state where it was not conditional to a state where it is conditional.
Response: The SDT believes it is unrealistic to consider the allowable usage of footnote 'b' in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. Other thresholds can be a point of reference or sanity check but in and of themselves are not sufficient for setting a threshold in this matter. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made. An entity can always approach a customer to request to a change in the type of service provided, with or without the consideration of footnote 'b' utilization. The institution of the formal process proposed here would bring the transmission customer into the decision making process which makes any condition open and transparent and which may initiate discussions on service type as		

Organization	Yes or No	Question 1 Comment
referenced above. No change made.		
Modesto Irrigation District	No	I am voting NO because there is no technical basis for use of the 75 and 25 MW absolute threshold values, regardless of the size of the utility's load, referenced in the proposed standard. WECC's past experience with implementation of arbitrary magnitudes for requirements (e.g., the 5% and 7% arbitrary magnitude contingency reserve requirements), has proved to be problematic. I would suggest investigating a technical basis for using a relative requirement, such as percentage of the utility's load, maybe 5% and 2.5%, respectively, and that it be based on technical requirements similar to those found in Table 1 of the WECC Criteria TPL-001-WECC-CRT-2.Thank you.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. Utilizing a percentage of an entity's Load may be problematic – when dealing with a small entity it could be a small value but still of rather large import and if dealing with a large entity could result in significant amounts of Load shed being planned. The FERC Order states that a percentage approach would not be appropriate for the aforementioned reasons. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made.		
Ameren	No	It appears that a least common denominator approach was used to develop the upper limit of 75 MW. Only 1 out of 18 respondents would drop 75 MW of load, and only two respondents would drop 61-70 MW of load. Our review of the data request responses concludes that only 22% of the respondents that presently utilize footnote "b" would drop more than 50 MW, and only 33% of the respondents that use footnote "b" would drop more than 40 MW. The proposed 75 MW limit is too high and is not supported by the responses to the data request. An upper limit of 40 MW is more appropriate, based on the data responses.

Organization	Yes or No	Question 1 Comment
Response: Based on the comments received, the majority of the industry does not agree that a lower threshold would be appropriate. The SDT does not believe that a least common denominator approach was utilized. The value selected is a reasonable limit based on the data received, potential vagaries in future considerations, and undefined system configurations that may arise. No change made.		
MidAmerican Energy Company	No	MidAmerican supports NSRF comments with one change. The proposed NSRF addition of "consideration of planned outages at demand levels for which the outage would be performed" to the text of footnote "b" after "following Contingency events" should not be added. If the addition is made, a reasonable time frame clarification is necessary and should be added such as "greater than 6 months". The proposed change would then read "consideration of planned outages greater than 6 months or longer at demand levels for which the outage would be performed".
Response: The SDT is not proposing to adopt the suggested change of the MRO NSRF. Please see the response to MRO NSRF above.		
Midwest Independent Transmission System Operator, Inc.	No	No. We believe footnote b in NERC TPL 002-1 and/or footnote 12 in TPL-001-2 should be eliminated because the intent of these standards is not to rely on non-consequential firm load shedding after a single contingency event. However, if these footnotes are not eliminated, there should be some limitation on how much firm load shed is allowed. We object to any level higher than the proposed 75 MW level and would prefer a level below 75 MW, but won't object to the proposed 75 MW level if the footnotes are not eliminated.
Response: The SDT believes that the wording of the footnote states that Non-Consequential Load shedding should not be the intent but recognizes that particular circumstances may result in such a planned action. The 75 MW level is being retained. No change made.		
Duke Energy	No	Regarding the maximum capacity item, we believe that 75 MW is much too low. While Duke Energy has not historically used the footnote, setting

Organization	Yes or No	Question 1 Comment
		the upper limit at 75 MW raises a concern. An upper limit of 75 MW severely limits the ability of a Transmission Planner to use the footnote. The 75 MW limit appears to be the maximum reported in the survey. The survey is a snapshot in time and to assume that there never have been nor never will be situations where the correct decision of a Transmission Planner and its stakeholders would be to exceed the 75 MW limit is illogical. The 75 MW limit is likely to create a situation where a Transmission Planner is forced to convert a network line to radial in order to remain in compliance with the standard, to the detriment of reliability to customers. The key to understanding use of the footnote is realizing that, in most cases, using the footnote is extremely unlikely to result in customer outages, because the probablility of the initiating contingency occurring under conditions requiring additional load shed is very low. A more reasonable upper limit would be the 300 MW limit that is established as the threshold for DOE Disturbance Reporting. It is also important to remember that no matter what upper limit is established, Non-consequential Load Loss of 25 MW or greater cannot be included in Year One of the Planning Assessment if the applicable regulatory authority or governing body responsible for retail electric service issues objects.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. DOE thresholds can be a point of reference or sanity check but in and of themselves are not sufficient for setting a threshold in this matter. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made.		
Southern California Edison Company	No	SCE believes that the maximum capacity threshold should be increased from 75 MW to 250 MW, as 250 MW is the limit utilized by the California Independent System Operator (CAISO) for a consequential load drop for a single contingency. The CAISO has a rigorous transmission planning

Organization	Yes or No	Question 1 Comment
		process that allows it to plan for and permit load shedding up to 250 MW.
Response: The footnote only applies to Non-Consequential Load Loss. Upon reviewing the comments, the SDT has seen that Demand that is not included as Firm Demand for footnote 'b' could be clarified as shown below. TPL-002-1c: footnote b) - ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load.		
Arizona Public Service Company	No	The 75 MW threshold is too low. No technical justification has been given for choosing 75 MW. It should be a significantly higher value for TPL-002. Currently AZPS does not use non-consequential load dropping to meet any standard but this option should be preserved. There could be times when alternate to the load dropping would be building a new transmission line costing hundreds of millions of dollar for a very low probability scenario of high load conditions. The threshold value should be 100 MW or more.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made.		
Northeast Power Coordinating Council	No	The 75MW of Firm Demand interruption is retail load that is being dropped. Dropping load in the general sense should not be endorsed, but it is recogn ized that there are special situations where it cannot be avoided. If a regulator responsible for retail load is comfortable with greater than 75MW being dropped in a rare situation, there should not be a requirement to build out of the situation. Provided there is no widespread, adverse effect on the reliability of the interconnected BES, the effect of a firm demand interruption on customers is under the purview of the applicable regulatory authority that is responsible for local

Organization	Yes or No	Question 1 Comment
		transmission and retail service over the load to be curtailed. There is no technical basis for the 75MW figure. It was included as a result of a Section 1600 Data Request, and is an arbitrary value. There should not be a limit without a technically supportable reliability based reason.
National Grid	No	The 75MW of Firm Demand interruption is retail load that is being dropped. Dropping load in the general sense should not be endorsed, but it is recognized that there are special situations where it cannot be avoided. If a regulator responsible for retail load is comfortable with greater than 75MW being dropped in a rare situation, there should not be a requirement to build out of the situation. Provided there is no widespread, adverse effect on the reliability of the interconnected BES, the effect of a firm demand interruption on customers is under the purview of the applicable regulatory authority that is responsible for local transmission and retail service over the load to be curtailed. There is no technical basis for the 75 MW figure with respect to reliability impact. Although, the value was developed by the SDT as a result of their review of Section 1600 Data Request, there was no reliability based analysis performed to identify whether the 75 MW is reasonable number. It is possible that a number either larger or lower could be identified if a reliability and cost-effective analysis is conducted.

Response: The SDT believes it is unrealistic to consider the allowable usage of footnote ‘b’ in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. No change made.

The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote ‘b’ by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote ‘b’. All of the Transmission Planners in the continental United States supplied their data in response to the data request. The SDT believes that any deviation from the threshold derived from the actual

Organization	Yes or No	Question 1 Comment
data may be viewed as a non-acceptable least common denominator approach. No change made.		
ISO New England	No	The draft footnote states that interruption "is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1." Attachment 1 appears to impermissibly require State participation in federal transmission planning processes. Further, it places the ERO in a Transmission Planning role, which exceeds the limits of the ERO's functions under Section 215 of the Federal Power Act. The current language appears to conflict with (1) federal statutes that are clear that wholesale electric transmission issues are matters of federal, and not state, jurisdiction, (2) orders of the Federal Energy Regulatory Commission ("FERC") regarding the role and independence Regional Transmission Organizations ("RTOs") with regard to transmission planning, and (3) Section 215 which limits NERC's authority to regulate "users, owners and operators" of the Bulk-Electric System. Further, the conditions appear to conflict with Section 215 of the Federal Power Act by placing the ERO in a transmission planning role and providing it with regulatory or functional oversight regarding the substance of transmission planning decisions. The ERO has the authority to develop and enforce standards, but is not a transmission planning entity and does not have the authority to substitute its judgment for registered Planning Authorities and Transmission Planners regarding the planning or operation of the bulk power system. Where a review is sought of planning entities' determinations, per FERC-filed Tariffs, they may be brought before FERC under Section 206 of the Federal Power Act. Because the footnote, and the associated Attachment appear to be in conflict with FERC Tariff and other statutory provisions, they should be removed. The footnote itself states, "An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events." The objective statement within the

Organization	Yes or No	Question 1 Comment
		standard does not appear to create a requirement and should be removed.
Response: The SDT does not believe that the footnote violates any regulations concerning transmission planning since there is no federal process as cited in the comment. The proposed process simply brings stakeholders, including local regulators, to the table in an open and transparent manner while setting criteria for when footnote 'b' can potentially be utilized. The ERO is not participating in the planning process. The role of the ERO is restricted to a determination of whether the planned utilization of footnote 'b' will cause an Adverse Reliability Impact to the BES. The ERO has no further role in the transmission planning process beyond that determination. No change made. The SDT believes that the objective statement referenced is an important consideration in the over-all planning process and thus should be retained. It sets the over-all tone and approach that should be followed. No change made.		
Deseret Generation & Transmission	No	The limitation of Non-Consequential load loss to the 25 MW-75 MW level with a hard limit at 75 MW is arbitrary and give no deference to the cost of the cure. In the West the high cost of a fix may not be in the public interest. The 75 MW hard high limit should be replaced with a soft 75 MW limit but allowing higher levels if the governing body or regulatory authority approves it.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. The SDT believes it is unrealistic to consider the allowable usage of footnote 'b' in the planning process without a hard cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. No change made.		
New England States Committee on Electricity (NESCOE)	No	The New England States Committee on Electricity (NESCOE) appreciates the opportunity to comment on NERC's proposed revisions to Transmission Planning (TPL) Reliability Standards relating to permissible applications of planned load interruption. NESCOE is New England's Regional State Committee and is governed by a board appointed by the

Organization	Yes or No	Question 1 Comment
		six New England Governors. These comments reflect the collective view of the six New England states.The issue of planned, limited load interruption rests at the central intersection of cost and reliability. It illustrates the fundamental balance that Commissioner Norris details in Order No. 762: the tradeoffs between "increasing levels of reliability and the costs that come along with achieving them." Transmission Planning Reliability Standards, Order No. 762, 139 FERC Â¶ 61,060 (April 19, 2012) (Norris, Comm'r. concurring in part and dissenting in part) at 2. NESCOE agrees with Commissioner Norris that, as a general matter, this balancing should translate to a more explicit consideration of costs in the NERC standard development process. Id. at 1. The language in footnote "b"- and corresponding footnote 12 of TPL-001-2-implicitly recognizes cost considerations in transmission planning by tolerating limited load shedding under defined circumstances. NESCOE offers below comments and suggestions in response to the SDT's questions. These responses reflect NESCOE's interest in planning for a robust bulk electric system while taking into account the magnitude of risk that a solution is intended to address and the costs associated with competing solutions. NESCOE appreciates the work of the SDT in attempting to respond to the Commission's directives and the time constraints under which the SDT was required to make changes to footnote "b." However, NESCOE is concerned that establishing a bright-line maximum capacity threshold that is an absolute ceiling is overly prescriptive and unnecessary to meet the Commission's directives. In Order 762, the Commission rejected the contention that regional stakeholder processes should unilaterally determine the appropriate criteria to apply in planning to interrupt firm load. Order 762 at P 32. However, provided that technical parameters are in place, the Commission stated that it would be "amenable" to regional stakeholders establishing such criteria if, for example, NERC or the applicable Regional Entity "developed an exception process that

Organization	Yes or No	Question 1 Comment
		provides flexibility in decisions based" on their expert view of regional considerations. Id. The SDT's proposal, however, would impose a one-size-fits-all requirement that forecloses a regional discussion of the quantitative and qualitative considerations that may justify an exception to the proposed 75 MW maximum capacity value. Such a regional discussion in ongoing in New England. In 2010, ISO New England introduced to stakeholders a draft Transmission Planning Load Interruption Guideline. The Guideline noted that load interruption should not be the principal tool to address transmission system reliability violations and highlighted the priority of reliable service. However, applying quantitative and qualitative criteria, the Guideline proposed for stakeholder discussion various levels of controlled load interruption in N-1-1 conditions-potentially up to hundreds of megawatts-that may be tolerated under clearly defined conditions. NESCOE did not take a view of the Guideline when it was presented for review and does not do so here. For now, the Guideline remains in draft form following stakeholder comment in 2011. However, imposition of a maximum capacity threshold that is an absolute ceiling for N-1 events and potentially, through revisions to footnote 12, N-1-1 events, would prematurely limit important regional discussions of this issue. A better approach, and one which the Commission appears amenable, would be to accompany any bright-line value with an exception process. There is recent precedent supporting such an approach: NERC proposed changes to its Rules of Procedure to accommodate exceptions to the proposed 100 kV bright-line Bulk Electric System definition. Separately, the footnote references Attachment 1 to the respective planning standards, which requires a stakeholder process review of the utilization of planned interruption. Such review is only triggered if utilization is sought in the Near-Term Transmission Planning Horizon, even though the footnote permits utilization of load interruption throughout

Organization	Yes or No	Question 1 Comment
		the planning horizon. NESCOE does not support this limiting language, which is at tension with an open and transparent planning process over the entire planning horizon. The term "Near-Term" should be stricken or further justification should be provided.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. The SDT believes it is unrealistic to consider the allowable usage of footnote 'b' in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. The SDT believes that the referenced exception process is what is being proposed. The proposed process sets up an open and transparent process for allowing such Load shed in specific conditions and with specific limitations. Any future revisions to footnote 12 will be accomplished through the approved standards development process and any discussion on changing threshold values would be part of that process. No change made. Footnote 'b' is not limited to the Near-Term Transmission Planning Horizon since the footnote recognizes that Firm Demand can be interrupted throughout the entire planning horizon. As drafted, the standard defines the stakeholder process as mandatory for the Near-Term Transmission Planning Horizon since there may not be time to implement other corrective actions but does not limit its use in the Long-Term Transmission Planning Horizon. How individual entities reflect the Long-Term Transmission Planning Horizon situations in its individual stakeholder processes is left to the entity to determine. No change made.		
Sacramento Municipal Utility District	No	There is no reliability benefit with an establish MW threshold. Implementing any threshold is descriptive and the standard should depict an outcome not the means of the outcome.
Response: The SDT believes it is unrealistic to consider the allowable usage of footnote 'b' in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. No change made.		
Public Utility District No.1 of Snohomish	No	We believe the survey significantly underestimated the use of Non-Consequential Load Shedding because the survey asked about past usage

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County Tacoma Power MEAG Power City of Austin Clark Public Utilities		of footnote b under Version 001, not about planned load shedding in TPL version 002 or the proposed footnote 12. TPL version 002 added several new contingencies, and also changed the Non Consequential Load shedding applicability for several contingencies. We have 4 specific concerns, followed by several suggested edits: 1) Analyzing the contingencies “P1.4 Loss of a Shunt Device” and “P2.1 Opening of a line section w/o a fault” are new requirements that will lead to increased use of footnote 12. It is common on fringes of the interconnected system to have weak sources. Significant utility investment will be redirected to remediate these fringe performance issues due to the P2.1 and its associated restrictions for firm load shedding and no RAS or UVLS mitigation. This is a low probability and low impact to the main grid contingency with a high mitigation cost, given the new mitigation restrictions. 2) Contingencies “P2.2 Bus Section fault” and “P2.3 Internal Breaker Fault” were previously defined as category “C multiple contingencies” with the restriction that the Firm Load shedding must be planned/controlled. However Version 002 no longer allows dropping nonconsequential load for EHV but removes all restrictions for HV load shedding. Since these contingencies result in opening the same breakers as category P1 contingencies, the use of footnote 12 should be consistent with P1. 3) Contingencies P3.1-P3.4 were previously defined as category “C multiple contingencies” with Firm loading shedding allowed. In version 2, these contingencies have been changed from allowing planned load shedding to only allowing Non-Consequential load shedding per footnote 12. Although this does not directly impact our utility, the survey results do not include utilities using “must-run” generation. 4) As demonstrated by multiple questions at the last webinar, many

Organization	Yes or No	Question 1 Comment
		utilities do not understand the definition of Non-Consequential Loads, and therefore may not have correctly reported the usage of Non-Consequential Load Shedding. The v2 changes cascade to the unfortunate conclusion that UVLS and RAS are no longer permitted as cost effective transmission performance mitigation, despite new low probability contingencies that drive performance problems at the edges of the network. -Proposed changes: A) Change the maximum amount from 75 MW to 300 MW. Several other standards including CIP have a strong technical basis for selecting 300 MW as the maximum limit for load shedding programs. B) Footnote 12 on contingency 2.1 should be replaced with a new footnote 15 that reads " 15. For this contingency, load which is served radial from a remaining single source line may be shed as if it were Consequential Load." This change would acknowledge that while P2.1 does involve just one element, the likelihood of occurrence is similar to bus section faults, so the resulting system performance requirements should be similar. C) The first two sentences of footnote 12 should be deleted. Remove the first sentence because it is general in nature and is a basic tenant of any load-serving utility. Remove the second sentence because column 7 of Table 1 explicitly states where Non-Consequential Load Loss is allowed. D) The third sentence of footnote 12 should have the words "under footnote 12" added. Without this addition, all Non Consequential Load Loss including the allowed loss for P4, P5 and P6 would still be subject to Appendix 1. The revised sentence would read "When Non-Consequential Load Loss is used under footnote 12 within the Near-Term ..."
Response: The SDT could not reasonably request data for unknown future conditions. The only viable mechanism for data input was the data request as it was formulated.		

Organization	Yes or No	Question 1 Comment
1) The SDT disagrees that planning events P1.4 and P2.1 are 'new' requirements in proposed TPL-001-2a. These requirements were previously approved by the industry and NERC Board of Trustees. No change made. **2)** The SDT disagrees that P2.2 and P2.3 planning events will open the same breakers as P1 planning events. For the EHV planning events cited, the standard approved by the industry and the NERC Board of Trustees accepted a raising of the bar by not allowing Non-Consequential Load Loss for these events. This posting of proposed TPL-001-2a does not change the application of the footnote. No change made. **3)** For the P3.1 – P3.4 planning events, the standard approved by the industry and the NERC Board of Trustees accepted a raising of the bar by not allowing Non-Consequential Load Loss for these events. This posting of proposed TPL-001-2a does not change the application of the footnote. No change made. **4)** Discussion of the proposed definition of Non-Consequential Load was provided during the various postings of proposed TPL-001-2. The SDT has received no comments from other utilities regarding confusion over the definition. Single Contingencies are not low probability events. No change made. A) The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. DOE thresholds such as the 300 MW referenced above can be a point of reference or sanity check but in and of themselves are not sufficient for setting a threshold in this matter. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made. B) For planning event P2.1, the standard approved by the industry and the NERC Board of Trustees accepted a raising of the bar by not allowing Non-Consequential Load Loss for these events. This posting of proposed TPL-001-2a does not change the application of the footnote. No change made. C) The SDT believes that such statements are important to set the tone and approach to be taken with the planning standards. No change made. D) The SDT agrees and has made the suggested clarification. TPL-001-2a: footnote 12 - However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1.		
Independent Electricity System Operator	No	We disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard. Provided there is

Organization	Yes or No	Question 1 Comment
		no adverse effect on the reliability of the interconnected bulk power system, the effect on customers of a firm demand interruption is the responsibility of the applicable regulatory authority or its agencies responsible for local transmission and retail service over the load to be curtailed.We propose replacing the sentence, in the footnote and in attachment one, section III that reads:”In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW.” with “In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss under footnote 12 for a Registered Entity that is a Canadian Entity (or a Mexican Entity) should be implemented in a manner that is consistent with/or under the direction of the Applicable Governmental Authority or its agency in Canada (or Mexico).
Hydro One Networks Inc.	No	We disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard. Provided there is no widespread, adverse effect on the reliability of the interconnected bulk electric system, the effect on customers of a firm demand interruption is the responsibility of the applicable regulatory authority or its delegated agencies responsible for local transmission and retail service over the load to be curtailed.If it is decided to proceed with the 75 MW or any other value, we propose replacing the sentence, in the footnote and in attachment one, section III that reads:”In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW.” with “In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss under footnote 12 for a non-US Registered Entity should be determined by the applicable Regulatory Authority or Governmental Authority or its delegated agency in that is responsible for retail electric service issues in that jurisdiction.”

Organization	Yes or No	Question 1 Comment
Response: Canadian entities are allowed to adopt ERO Reliability Standards, reject them outright, or adapt them for their own use within the confines of provincial regulations. Nothing has changed in that regard with this proposed standard. The effective date language covers the situation. No change made.		
NB Power Transmission	No	We disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard. Provided there is no widespread, adverse effect on the reliability of the interconnected bulk electric system, the effect on customers of a firm demand interruption is the responsibility of the applicable regulatory authority or its delegated agencies responsible for local transmission and retail service over the load to be curtailed.
NBSO	No	We do not agree with setting a MW limit for non-consequential load loss. The allowable amount should be determined and approved by the jurisdiction of the area(s) whose load is affected. The intent of the TPL standard and this footnote is to ensure that if non-sequential load loss is accounted for or relied up to ensure BES reliability (as assessed in the planning horizon), that such a decision needs to be approved by the appropriate jurisdiction. Non-consequential load loss being applied or considered to achieve BES reliability in planning assessment is in itself not a BES reliability concern that rises up to a continent-wide reliability standard.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. DOE thresholds such as 300 MW can be a point of reference or sanity check but in and of themselves are not sufficient for setting a threshold in this matter. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made.		

Organization	Yes or No	Question 1 Comment
Western Area Power Administration	No	We do not support a maximum threshold of 75 MW or any MW level. It is not appropriate to enforce a one size fits all maximum value. There are no apparent reliability benefits from implementing a capacity loss limitation...why not pick 300 MW? Also we are not sure what prompted the additional distinction of allowing the load shedding only in the near-term planning horizon...please elaborate.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. DOE thresholds such as 300 MW can be a point of reference or sanity check but in and of themselves are not sufficient for setting a threshold in this matter. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made. Footnote 'b' is not limited to the Near-Term Transmission Planning Horizon since the footnote recognizes that Firm Demand can be interrupted throughout the entire planning horizon. No change made.		
Platte River Power Authority	No	We do not support a maximum threshold. 1) It is not appropriate to enforce a one size fits all maximum value that might unnecessarily over-burden some communities. 2) The public process proposed in this standard provides significant transparency from the transmission utilities and opportunity for community input to decisions that will impact both the community's reliability and rates. 3) Leave the maximum capacity threshold decisions to local regulatory commissions and Boards of Directors.
Response: (1) The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value		

Organization	Yes or No	Question 1 Comment
for the amount of Load that could be planned to be shed under footnote 'b'. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made. (2) Thank you for your support. (3) The SDT believes it is unrealistic to consider the allowable usage of footnote 'b' in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. Local regulators are involved in the process through the wording in Attachment 1, Sections I and III. No change made.		
California Independent System Operator	No	While we have voted in favor of supporting the changes to the footnote and to move forward with the adoption of the standard, we remain concerned that there is not a good foundation for concluding that loss of load over 75 MW poses a reliability risk to the system compared to some higher MW threshold. Instead, the 75 MW capacity threshold is simply based on the current maximum planned loss of Non-Consequential Load. While we support minimizing reliance on Non-Consequential Load Loss, there may be scenarios where such reliance is unavoidable in the near-term, and therefore may be needed until capital upgrades can be put in place. At a minimum, the footnote or standard should provide for an exception process, should it be necessary for a planned Non-Consequential Load Loss of greater than 75 MW.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. The SDT believes that the referenced exception process is what is being proposed. The proposed process sets up an open and transparent process for allowing such Load shed in specific conditions and with specific limitations. No change made.		
Tri-State Generation & Transmission Association	No	

Organization	Yes or No	Question 1 Comment
LCRA Transmission Service Corporation	No	
Response: Without a specific comment, the SDT is unable to respond.		
TVA Transmission Reliability Engineering and Controls	Yes	TVA agrees with the general text; however, TVA believes that the 75 MW limit is too low. TVA believes that a better limit would be 100 MW - which is the amount for load shedding required to be reported under OE-417 under emergency operational policy. This would allow some future load growth as well as any possible new loads that may develop quickly in which a utility may not have time to complete necessary projects in a corrective action plan.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. DOE thresholds can be a point of reference or sanity check but in and of themselves are not sufficient for setting a threshold in this matter. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made.		
Southwest Power Pool Reliability Standards Development Team	Yes	
Bonneville Power Administration	Yes	
SERC EC Planning Standards Subcommittee Associated Electric Cooperative, Inc.	Yes	
Southern Company	Yes	
American Electric Power	Yes	
Seminole Electric Cooperative, Inc.	Yes	

Organization	Yes or No	Question 1 Comment
Public Service Company of New Mexico	Yes	
Idaho Power Company	Yes	
SCE&G	Yes	
Lincoln Electric System	Yes	
Georgia Transmission Corp	Yes	
Response: Thank you for your support.		

2. **Do you agree with the description and components of the Stakeholder Process in Section I of Attachment 1? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: There was little or no commonality in the comments submitted and the responses are mainly statements clarifying SDT intent as shown in the individual responses.

The following change was made due to industry comment:

TPL-002-1c: footnote b) - ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load.

Organization	Yes or No	Question 2 Comment
Southern Company	No	The complex stakeholder process described in Attachment 1 should be required only if the amount of planned load shed exceeds 25 MW or the contingency is greater than 300 kV. Since the average use given in the survey was 19 MW and there is no evidence of harm to the BES reliability resulting from that use, there is no good reason to require such a stakeholder process for amounts less than 25 MW. The stakeholder process should only be required for larger amounts of load.
SCE&G	No	No, We recommend that up to 25 MW of planned interruption be allowed without triggering the need for a stakeholder process. Since the average use given in the survey was 19 MW and there is no evidence of harm to the BES reliability resulting from that use, there is no reason to require a stakeholder process for amounts less than 25 MW. This is consistent with the value cited in Section III.
TVA Transmission Reliability Engineering and Controls	No	TVA recommends that up to 25 MW of planned interruption be allowed without triggering the need for a stakeholder process. Since the average use given in the survey was 19 MW and there is no evidence of harm to the BES reliability resulting

Organization	Yes or No	Question 2 Comment
		from that use, there is no reason to require a stakeholder process for amounts less than 25 MW. This is consistent with the value cited in Section III.
SERC EC Planning Standards Subcommittee Associated Electric Cooperative	No	We recommend that up to 25 MW of planned interruption be allowed without triggering the need for a stakeholder process. Since the average use given in the survey was 19 MW and there is no evidence of harm to the BES reliability resulting from that use, there is no reason to require a stakeholder process for amounts less than 25 MW. This is consistent with the value cited in Section III.
Response: The SDT disagrees that the proposed process is complex or unnecessary. The SDT used the Board of Trustees approved standard as a starting point for this draft. FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. The SDT believes that all uses of footnote 'b' should go through the stakeholder process. No change made.		
Seminole Electric Cooperative, Inc.	No	#1.It is unclear what factors must be met in order to be an affected stakeholder under the Stakeholder Process in Attachment 1? This process appears to be devoid of any objective factors that can assist an entity in determining whether a party is a stakeholder or not. NERC should define what an "affected stakeholder" is or list factors to assist industry in making such a determination. #2.In Standard TPL-002-1c, Attachment 1, Section I. "Stakeholder Process," there was a section added at the end of this subsection that is three lines in length. This section states that a stakeholder process does not need to be repeated unless there has been a "material change." It is clear from the latest webinar presentation on this Project that this language is not "clear and unambiguous". NERC does not present any metrics, whether qualitative or quantitative, to guide industry as to when a material change occurs to an application of footnote 'b.' Without any metrics to guide industry, it is bewildering that NERC reasons that entities will consistently interpret what a material change constitutes. Therefore, SECI believes that this provision is in conflict with the NERC Rules of Procedure and FERC Order

Organization	Yes or No	Question 2 Comment
		762. #3.In Standard TPL-002-1c, Attachment 1, Section I. “Stakeholder Process,” the requirement that the process “shall be documented” was deleted from the first paragraph. It does not appear to be reasonable that a process that is not written, nor known to any stakeholder, meets the common understanding of “open and transparent.” Seminole believes that the requirement that the process be documented and that documents be available to potential affected parties be reinstated into the Standard.
Response: 1. The SDT believes that the planning entity is in the best position to identify affected stakeholders and that any attempt to codify a list of such stakeholders in the proposed standards could lead to errors due to the necessity of having to adopt a one size fits all approach. No change made. 2. The SDT believes that the planning entity has the best understanding of when a change would become material. With the large range of design philosophies and geographic difference between the entities within NERC, it is not practical to adopt a single one size fits all approach. In addition, since the use of footnote ‘b’ will be a part of the entity’s Corrective Action Plans, interested stakeholders will have the opportunity to question the continued use of footnote ‘b’. No change made. 3. The SDT believes the ‘documented’ terminology is unnecessarily redundant since the entity must be able to demonstrate compliance to its Compliance Enforcement Authority. It should not be necessary to mandate that an entity has to document a process. No change made.		
NBSO	No	(1) The process presented in Section I of Attachment I is overly prescriptive. This Section needs only to stipulate that the proposed utilization of the footnote be reviewed through an open and transparent stakeholder process developed and/or approved by the jurisdiction (a Regional Entity or regulatory authority) of the area(s) whose load is affected area. (2) There is no basis to support allowing the utilization of the footnote in the Near-Term Transmission Planning Horizon of the Planning Assessment only. The footnote itself should not explicitly restrict its utilization to only the Near-Term horizon. Often, in the long-term planning horizon, when approval for transmission addition

Organization	Yes or No	Question 2 Comment
		or reinforcement cannot be obtained for whatever reasons, utilization of the footnote is considered and adopted, subject to stakeholder's and regulatory authority's approvals. Note that it is impractical to add or reinforce transmission facilities in a near-term planning (e.g. Year 0ne) time frame and hence the proposed provision does not allow for utilizing the footnote for the interim period before new or reinforced transmission facilities are put in place. We suggest removing the word "Near-Term".
Response: (1) FERC remanded the standard because they wanted the stakeholder process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. The balloted draft added the indicated detail and specificity to the already approved approach. No change made. (2) Footnote 'b' is not limited to the Near-Term Transmission Planning Horizon since the footnote recognizes that Firm Demand can be interrupted throughout the entire planning horizon. As drafted, the standard defines the stakeholder process as mandatory for the Near-Term Transmission Planning Horizon since there may not be time to implement other corrective actions but does not limit its use in the Long-Term Transmission Planning Horizon. How individual entities reflect the Long-Term Transmission Planning Horizon situations in its individual stakeholder process is left to the entity to determine. No change made.		
ACES Power Marketing Standards Collaborators	No	(1) Many RTOs have well organized stakeholder processes that could be utilized to satisfy Attachment 1. Because the TPL standards apply to both the PC and TP, one may conclude that both functions need to have a stakeholder process. Rather, we think that the TP should be able to rely on its PC's stakeholder process. We recommend clarifying Attachment 1 that it is acceptable for the TP to rely on the PC's process and that both entities are not required to have redundant processes. The most important point is that stakeholders have an opportunity to participate.
Response: The SDT believes that it has covered this possibility in the revised language posted for this draft allowing an entity to use an existing process as long as it meets the criteria. Such usage is not restricted to a particular entity and as long as each entity is able to demonstrate that it meets the items in Section I, entities can share the same process. No change made.		
Minnkota Power Cooperative	No	1. MPC QUESTION: In Attachment 1 Section I, what is the definition of a

Organization	Yes or No	Question 2 Comment
Otter Tail Power Company		"stakeholder"? a. Is this intended to apply to multiple NERC functional entities (DP, TO, TOP, LSE), public residential customers, and/or business owners that are affected by system contingencies? b. RECOMMENDATION: Define stakeholder to be "affected Transmission Owners, Transmission Operators, Distribution Providers, and Load-Serving Entities." We believe it is most appropriate for the Transmission Owners, Transmission Operators, Distribution Providers, and Load-Serving Entities to objectively evaluate the risks of load shedding in a local area against the cost impact of a large transmission project on the rate base. 2. MPC QUESTION: In Attachment 1 Section I item 1, what does "including applicable regulatory authorities" refer to? a. Is this the same body that "applicable regulatory authority or governing body" refers to in Section III? b. Are these requirements still applicable if the 25 MW threshold in Section III is not passed? c. RECOMMENDATION: Attachment 1 Section I Item 1 could read "... including applicable regulatory authorities or governing bodies responsible for retail electric service as described in Section III. A clearly defined statement allows the Transmission Planner and Planning Coordinator to identify the appropriate parties to be included in every instance Attachment 1 is used.
Response: 1. The SDT believes that affected stakeholders should include the list of NERC functional entities and others. Transmission customers, Planning Coordinators, Transmission Planners, and regulatory authorities with retail jurisdiction should typically be included. The SDT believes that the planning entity has the best understanding of who an affected stakeholder will be and that any attempt to codify a list of such stakeholders in the proposed standards could lead to errors due to the necessity of having to adopt a one size fits all approach. No change made.		

Organization	Yes or No	Question 2 Comment
2. a. Yes, it is the same as those in Section III. b. Yes, these requirements are applicable for each circumstance of planned use of footnote b. The SDT believes that the use of the stakeholder process is necessary each time that an entity utilizes footnote b. c. The SDT did not accept your recommendation. The SDT believes that the suggested change may be too limiting since it refers to a single governing body. No change made.		
Western Area Power Administration	No	A public process seems out of place in a reliability standard.
Response: FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. No change made.		
Manitoba Hydro	No	A stakeholder process should not be required in jurisdictions where a legislation already authorizes interruptions, as consent of stakeholders cannot override legislation.
Response: The SDT does not believe that the consent of stakeholders will override legislation. The proposed process provides an opportunity for affected stakeholders, including regulators, to have the necessary information to fully understand the impacts of the planned use of footnote b. If the applicable regulator does not object to the planned use of footnote b, it may be used. No change made.		
Iberdrola USA	No	"Stakeholders" is undefined - would this be the same stakeholder body identified in the planning process of the Open Access Transmission Tariff?
Response: In many instances, the affected stakeholders would be the same stakeholders identified in the Open Access Transmission Tariff planning process. However, the SDT believes that the planning entity has the best understanding of who an affected stakeholder will be and that any attempt to codify a list of such stakeholders in the proposed standards could lead to errors due to the necessity of having to adopt a one size fits all approach. No change made.		

Organization	Yes or No	Question 2 Comment
Public Utility District No.1 of Snohomish County MEAG Power City of Austin Clark Public Utilities Tacoma Power	No	In the first sentence, remove the words “as an element of a Corrective Action Plan.” There are cases on the fringes of the system where Non-Consequential Load Loss is the preferred alternative in both the long term and short term, not as a temporary patch. Requiring the stakeholder process as part of Corrective Action Plan implies that using footnote 12 cannot be the long term choice. Since a Corrective Action Plan is a “list of actions and an associated timetable for implementation to remedy a specific problem,” using this term removes the stakeholders ability to evaluated the costs and benefits and instead requires them to treat this a problem where the only solution is building new facilities.
Response: The stakeholder process is not required as part of a Corrective Plan. What the attachment states is that use of the footnote cannot be part of the Corrective Action Plan unless it has gone through the process. And the SDT disagrees that inclusion of this language ever requires a construction solution. Bullet #7 in Section II requires that alternatives to Load shed be presented for process participants to see as well as providing the rationale for not selecting those alternatives. Cost and benefits can certainly be part of this rationale. No change made.		
Ameren	No	It is our opinion that that the stakeholder process should be conducted at least once every five years if non-consequential load is planned to be dropped as part of the Corrective Action Plan to meet single contingency events. If conditions have not materially changed since the last review, this information should still be communicated to the stakeholders.
Response: The SDT did not want to present repetitive information and unduly burden the planning entity or the stakeholder in this process. However, an entity can always do more than what is required in the standard. No change made.		
Tri-State Generation & Transmission Association	No	NERC Functional Model definitions for Planning Authorities and Transmission Planners do not include the types of activities being proposed in “Attachment 1.” How is it appropriate to mandate to functional entities functions that are outside those defined in the NERC functional model?
Response: The NERC Functional Model is a guideline for activities required of cited functional entities. It is periodically updated as		

Organization	Yes or No	Question 2 Comment
conditions change. While the activities mentioned in the standard may not be explicitly spelled out in the NERC Functional Model, the SDT does not believe that they are out of scope for either a Planning Coordinator or a Transmission Planner. No change made.		
New England States Committee on Electricity (NESCOE)	No	NESCOE appreciates the efforts of the SDT in developing a stakeholder process for considering the use of load interruption in system planning. NESCOE especially appreciates the heightened role accorded to states in light of jurisdictional issues raised by the prospect of shedding load and implications for retail customers. States must be intimately involved in weighing reliability considerations against the economic implications of alternative approaches. Regarding the language in Section I, see the comments above regarding striking "Near-Term" in this context. NESCOE also suggests that additional clarity is needed regarding the intended meaning of "applicable regulatory authorities or governing bodies responsible for retail electric service issues." This language potentially implicates state agencies beyond public utility commissions (e.g., state consumer advocates, attorneys general) and could create confusion for state agencies as well as transmission planners that are required to provide notice to such entities and, pursuant to Section III, provide a process for regulatory review. Instead, the SDT should revise the language to read "electric retail regulatory authorities," a term with clear meaning that the Commission has itself used. See, e.g., Order 719.
Response: Please see the response to question 1. The SDT believes that there may be instances where other regulatory bodies may want to be involved in the stakeholder process. The SDT disagrees that the proposed language will create confusion for state agencies or transmission planners. The SDT believes that the planning entity has the best understanding of who an affected stakeholder will be and that any attempt to codify a list of such stakeholders in the proposed standards could lead to errors due to the necessity of having to adopt a one size fits all approach. No change made.		
Independent Electricity System Operator	No	No. The process presented in Section I is overly prescriptive. If a section that prescribes the principles of a stakeholder process is required, then for Canadian entities this section should simply state that any threshold should be established in

Organization	Yes or No	Question 2 Comment
		a manner consistent with other service levels that apply to local transmission and retail service for the load to be curtailed. Corrective action plans can rarely be implemented in a one-year time frame, and in some cases, limited use of Non-consequential Load Loss will be preferable to unaffordable transmission enhancements, therefore we believe that the use of footnote ‘b’/’12’ should not be limited to the Near-Term Transmission Planning Horizon. We propose that the phrase “the Near-Term Transmission Planning Horizon of” be deleted from the opening paragraph.
Response: Canadian entities are allowed to adopt ERO Reliability Standards, reject them outright, or adapt them for their own use within the confines of provincial regulations. Nothing has changed in that regard with this proposed standard. The effective date language covers the situation. No change made. The SDT agrees that it may be difficult to implement construction options in a one year time frame and that the limited use of Non-Consequential Load Loss may be an acceptable option. Footnote ‘b’ is not limited to Year One or to the Near-Term Transmission Planning Horizon since the footnote recognizes that Firm Demand can be interrupted throughout the entire planning horizon. As drafted, the standard defines the stakeholder process as mandatory for the Near-Term Transmission Planning Horizon since there may not be time to implement other corrective actions but does not limit its use in the Long-Term Transmission Planning Horizon. How individual entities reflect the Long-Term Transmission Planning Horizon situations in its individual stakeholder process is left to the entity to determine. No change made.		
Midwest Independent Transmission System Operator, Inc.	No	No. MISO objects to a stakeholder process as outlined in Attachment 1. See our comments under Question 5.
Response: Please see response to question 5.		
Electric Reliability Council of Texas, Inc.	No	Please see ERCOT's response to Question 1 - stakeholder processes are not appropriate for NERC standards.
Response: Please see response to question 1.		

Organization	Yes or No	Question 2 Comment
Public Service Company of New Mexico	No	PNM voted yes to the Standard as a whole but would like the SDT to consider the following concern: Part II.2.b of Attachment 1 that requires an assessment of the effect of the use of Non-Consequential Load Loss under Footnote B on the health, safety, and welfare of the community, and PNM believes that assessments of this nature are entirely subjective and will be difficult to comply with and even more difficult to audit. It is our belief that this criteria should be removed from the Standard prior to its ultimate submittal to NERC.
Response: The SDT understands the concerns and has clarified the wording accordingly. The intent of the SDT is that this action should be analogous to that required in approved EOP-001-2.1b. Section II, Bullet 2b. ~~Assessment~~ A description of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community		
NB Power Transmission	No	The process in Attachment 1 is overly prescriptive. Attachment 1, if retained, needs only to stipulate that the proposed utilization of the footnote be reviewed through an open and transparent stakeholder process in compliance with the applicable regulatory authority oversight.
Response: FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. No change made.		
Hydro One Networks Inc.	No	The process presented in Section I is overly prescriptive. If a section that prescribes the principles of a stakeholder process is required, then for non-US entities this section should simply require that the process must be approved by the applicable Regulatory Authority or Governmental Authority or its delegated agency that is responsible for local transmission and retail service for the load to be curtailed in that jurisdiction.
Response: Canadian entities are allowed to adopt ERO Reliability Standards, reject them outright, or adapt them for their own use		

Organization	Yes or No	Question 2 Comment
within the confines of provincial regulations. Nothing has changed in that regard with this proposed standard. The effective date language covers the situation. No change made.		
LCRA Transmission Service Corporation	No	
Response: Without specific comments, the SDT is unable to respond.		
Xcel Energy	Yes	The possibility of NCLL is always present, whether in the planning or operational arena. Section I (#5) should however specifically state that in the dispute resolution process a stakeholder does not have right of refusal for NCLL. This should be especially true when a transmission project has been proposed and NCLL in the interim is required due to the regulatory process, equipment lead time, etc. preventing the completion of project at an earlier time.
Response: Bullet #5 does not require specific attributes of the dispute resolution process. The SDT believes that the attributes of the stakeholder process should be defined by the entity during the development of the stakeholder process. No change made.		
MRO NSRF USACE MidAmerican Energy Company	Yes	(1) In Attachment 1 Section I, what is the definition of a “stakeholder”? Which NERC functional entities would be included (TO, TOP, LSE)? Are the public residential and/or business owners that are affected included in the definition? Some parties may assume that local government representatives or residential or business owners are included as stakeholders. We believe it is most appropriate for the Transmission Owners, Transmission Operators, and Load-Serving Entities to objectively evaluate the risks of load shedding in a local area against the cost impact of a large transmission project on the rate base. RECOMMENDATION: Define stakeholder to be “affected Transmission Owners, Transmission Operators, and Load-Serving Entities.” (2) In Attachment 1 Section I item 1, what does “including applicable regulatory authorities” refer to? Is this the same body that “applicable regulatory authority or governing body” refers to in Section III? Are these requirements still applicable if the

Organization	Yes or No	Question 2 Comment
		25 MW threshold in Section III is not passed? RECOMMENDATION: Attachment 1 Section I Item 1 could read "... including applicable regulatory authorities or governing bodies responsible for retail electric service issues as described in Section III. A less vague statement allows the important parties to be included in every instance Attachment 1 is used.
Response: (1) In many instances, the affected stakeholders would be the same stakeholders identified in the Open Access Transmission Tariff planning process. However, the SDT believes that the planning entity has the best understanding of who an affected stakeholder will be and that any attempt to codify a list of such stakeholders in the proposed standards could lead to errors due to the necessity of having to adopt a one size fits all approach. No change made. (2) The term applies to any applicable, interested regulatory authority and is not necessarily the same body as mentioned in Section III. Conversely, the regulatory body cited in Section III would certainly be one of the regulatory bodies referred to in Section I. If the result of Section I is that the entity is not going to move forward with the plan, then Section III will never occur. No change made.		
Texas Reliability Entity	Yes	Attachment 1, section I (Stakeholder Process) should be clarified to specify which 'responsible entity' needs to utilize or develop a transparent stakeholder process. For example, if a contingency event in Entity A's system causes Entity B to have to shed non-consequential firm load to meet the BES performance requirements, which Entity is responsible for ensuring the required review? TRE proposes adding the following sentence to the first paragraph to assign responsibility for this type of scenario: "The Planning Coordinator or Transmission Planner accountable for the contingency event will be responsible for implementing the stakeholder process and regulatory review."
Response: The SDT believes that the current terminology is clear in that it is the entity that plans to utilize the footnote that needs to initiate the process. No change made.		
California Independent System Operator	Yes	There is no basis to support only allowing the utilization of the footnote in the Near-Term Transmission Planning Horizon of the Planning Assessment. The footnote itself should not explicitly restrict its utilization to only the Near-Term horizon. Often, in the long-term planning horizon, when approval for transmission addition or

Organization	Yes or No	Question 2 Comment
		reinforcement cannot be obtained for a variety of reasons, utilization of the footnote is considered and adopted, subject to stakeholder's and regulatory authority's approvals. Note that it is impractical to add or reinforce transmission facilities in a near-term planning (e.g. Year One) time frame and hence the proposed provision does not allow for utilizing the footnote for the interim period before new or reinforced transmission facilities are put in place. We suggest to remove the word "Near-Term".
Response: Footnote 'b' is not limited to the Near-Term Transmission Planning Horizon since the footnote recognizes that Firm Demand can be interrupted throughout the entire planning horizon. As drafted, the standard defines the stakeholder process as mandatory for the Near-Term Transmission Planning Horizon since there may not be time to implement other corrective actions but does not limit its use in the Long-Term Transmission Planning Horizon. How individual entities reflect the Long-Term Transmission Planning Horizon situations in its individual stakeholder process is left to the entity to determine. No change made.		
Southern California Edison Company	Yes	The Stakeholder Process in Section I of Attachment 1 is similar to the method effectively used by the CAISO to manage and incorporate stakeholder input in its annual transmission planning process.
Platte River Power Authority	Yes	Although these descriptive steps for a public process seem out of place in a reliability standard, Section 1 is in line with the planning principles of FERC Order 890.
Southwest Power Pool Reliability Standards Development Team	Yes	
Duke Energy	Yes	
Bonneville Power Administration	Yes	
Florida Municipal Power Agency	Yes	

Organization	Yes or No	Question 2 Comment
Arizona Public Service Company	Yes	
American Electric Power	Yes	
Deseret Generation & Transmission	Yes	
American Transmission Company	Yes	
Massachusetts Attorney General	Yes	
Idaho Power Company	Yes	
ISO New England	Yes	
Georgia Transmission Corp	Yes	
Modesto Irrigation District	Yes	
Response: Thank you for your support.		

3. Do you agree with the Information for Inclusion in the Stakeholder Process contained in Section II of Attachment1? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Summary Consideration: Most of the commenters asked questions about the intent of the SDT in particular areas and the SDT has provided individual responses accordingly.

There was one major overriding concern about Section II, Bullet 2b on the assessment on public health and safety. The SDT has clarified its intent and also pointed out that the action required for this bullet item is analogous to what is already required in approved EOP-001-2.1b.

Some commenters also questioned the use of the term 'mitigate' in Section II, Bullet 5. The SDT has clarified this language.

The following clarifying changes have been made due to industry comments:

TPL-002-1c: footnote b) - ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load.

Section II, Bullet 2b. ~~Assessment~~ An explanation of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community

Section II, Bullet #5. Future plans to ~~mitigate~~ alleviate the need for Firm Demand interruption under footnote 'b'

Organization	Yes or No	Question 3 Comment
TVA Transmission Reliability Engineering and Controls	No	TVA would like to propose that this Stakeholder process be postponed in the event that a transmission fix for a load drop issue was already planned within the next 2 or 3 years. Thus the stakeholder process would only occur for projects that had no fix planned within the next couple of years. TVA is also not sure how to satisfactorily address "health, safety, and welfare of the community" - TVA would appreciate some guidance on how to properly address this.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>TVA believes that item 1.b of Section II could contain CEII information and should have limited distribution. The appropriate non-disclosure agreements would need to be developed to prevent widespread publication of the information.</td></tr>
<tr><td colspan="3">Response: The SDT believes that the stakeholder process should occur whenever footnote ‘b’ is proposed to be utilized. The construction option in later years will be a part of the information provided in the stakeholder process for review. In this case, there will only need to be one review through the stakeholder process, if there are no material changes before the construction option is completed. No change made.

The SDT understands the concerns and has clarified the wording accordingly. The intent of the SDT is that this action should be analogous to that required in approved EOP-001-2.1b.

Section II, Bullet 2b. ~~Assessment~~ An explanation of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community

If an entity believes that CEII information is involved then the entity should use the appropriate mechanisms to protect that information while still providing the basics of the information needed for the process to continue. No change made.</td></tr>
<tr><td>ACES Power Marketing Standards Collaborators</td><td>No</td><td>(1) Adding the word “effect” on the health, safety, and welfare of the community creates more confusion regarding what is needed for the assessment. We recommend removing the effect clause from Section II.

(2) We disagree that the Transmission Planner should be required to provide an assessment at all on the health, safety and welfare of the community. Attachment 1, Section 2a identifies the types of customers that are impacted without needing a formal assessment. Stakeholders will have an opportunity to provide information on impacts of planned load shedding through either the Transmission Planner’s stakeholder comment process or through the local regulatory agency’s stakeholder comment process. Further, these planned interruptions of firm demand are expected to be short in nature so any impact would be de minimis. Finally, an assessment on the health, safety and welfare of the community is an unnecessary burden on the registered entity and is better suited for local governments that can speak through the stakeholder process.</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
		(3) Bullet 3 is based on available historical information. While this seems reasonable, we have concerns because of the rare instances that Non-Consequential Load Shed actually occurs. If a TP uses Non-Consequential Load Shed for the first time, there is no historical information. What would be an acceptable basis for the first use of Non-Consequential Load Shed when the entity is without historical information? (4) Expected time duration of the planned load shed is too speculative and should not be required because any duration will likely be a guess. When actual contingencies occur, the time of restoration varies and any time that was selected prior to the event is not likely to be correct. We do not see the value in predicting the duration time because there is too much uncertainty about how long an outage will really last. The SDT needs to clarify what is expected for the duration of the planned load shed. (5) While we appreciate that the response to our comments clarified the intent is that "Possible future plans could include a decision not to mitigate the need for Firm Demand interruption," the language in the Attachment simply does not reflect this. The Attachment specifically states "Future plans to mitigate the need for Non-Consequential Load Loss." A decision not to mitigate the need for Firm Demand interruption is not a future plan to mitigate. Consequently, Attachment 1, section II.5 will need to be modified to implement this intent. Otherwise, this language is certain to be interpreted as requiring a mitigation plan.

Response: (1) and (2) The SDT understands the concerns and has clarified the wording accordingly. The intent of the SDT is that this action should be analogous to that required in approved EOP-001-2.1b.

> Section II, Bullet 2b. ~~Assessment~~ An explanation of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community

(3) Historical performance is not limited to Contingencies which result in Non-Consequential Load Loss. The estimated frequency should be based on an entity's average historical performance of similar Facilities applied to the specific Element being evaluated. No change made.

Organization	Yes or No	Question 3 Comment
(4) The expected duration could be a range of values based on various assumptions. In the planning environment the entity should be able to analyze the situation and determine an expected duration for which an interruption would be in place. No change made. (5) The SDT agrees and has changed the language accordingly. 5. Future plans to ~~mitigate~~ alleviate the need for Firm Demand interruption under footnote 'b'		
Minnkota Power Cooperative Otter Tail Power Company	No	1. MPC QUESTION/COMMENT: In Attachment 1 Section II item 2b, "Assessment of the effect ... on the health, safety, and welfare of the community" is vague. Clarification is requested.a. RECOMMENDATION: Remove Item 2b because it requires the assessment of the footnote application impact on the potential health, safety, and welfare of the community. These types of assessments should be eliminated because they are not electric system reliability matters and were not stipulated by FERC. In the event that the Standards Development teams choses to keep item 2b, then add language semi-defining this as follows in Attachment 1 Section II Item 2b "...health, safety, and welfare of the community as determined by impact on critical health and emergency services." This allows the Transmission Planner and Planning Coordinator to identify the appropriate parties affected by the contingency to be analyzed in every instance Attachment 1 is used.
American Transmission Company	No	ATC recommends the following change in Section II of Attachment 1 applicable to both standards TPL-002-1c [page 8] and TLP-001-2a [page16]:Remove Item 2b altogether because it requires the assessment of the footnote application impact on the potential health, safety, and welfare of the community. These types of assessments should not be required in the Standards because they are not electric system reliability matters and were not stipulated within the FERC Order762.
Bonneville Power Administration	No	BPA does not support including information under Section II.2.b, an assessment of the use of Non-Consequential Load Loss on the health, safety, and welfare of the community. It would be nearly impossible for a planner to predict this in a future case since it is hard to predict what loads will actually materialize in the future. In addition, this information does not support reliability of the BES since reliability of

Organization	Yes or No	Question 3 Comment
		the transmission system is assessed by meeting required technical performance for certain contingencies and under certain conditions.
Arizona Public Service Company	No	Item 2b: Reference to health, safety, and welfare is unnecessary. All demand interruption are going to have some impact on health, safety, and welfare. The impact is subjective and will simply result in unnecessary study reports by consultants and will act as a road block.
Iberdrola USA	No	Regarding the documentation required for item 2.b, how are “health, safety, and welfare of the community” to be assessed? What are the metrics? How would compliance with this provision be evaluated?
MRO NSRF MidAmerican Energy Company USACE	No	Remove Item 2b because it requires the assessment of the footnote application impact on the potential health, safety, and welfare of the community. These types of assessments should be eliminated because they are not electric system reliability matters and were not stipulated by FERC.
Southern California Edison Company	No	SCE participates in the rigorous CAISO annual transmission planning process that considers the information included in the proposed Section II of Attachment 1. However, the proposed language in Section II.2.b. “Assessment of the effect of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community,” seems overly broad and confusing. The California Public Utility Commission (CPUC) and CAISO presently consider these items before approving transmission plans. It is unclear what type of information would be required in order to meet the seemingly broad request contained in Section II.2.b. SCE believes that the language of Section II.2.b. should be removed from Attachment 1, or alternatively, the language should be revised to specifically exempt critical loads, such as hospitals, fire department facilities, law enforcement facilities, and correctional facilities.
Public Utility District No.1 of	No	We suggest removing section 2b “Assessment...health, safety...” for three reasons:

Organization	Yes or No	Question 3 Comment
Snohomish County MEAG Power Clark Public Utilities		1)All outages have a negative impact on the community. Outages under footnote 12 do not inherently have more significant impact per MWhr lost than other outages allowed per Table 1. By requiring additional analysis for a similar societal impact, this provision discriminates against utilities at the fringes of the system. 2) While reminding planners to consider that their decisions do have real impacts to real people is a laudable goal, including this provision opens the door to significant legal liability and regulatory uncertainty. 3) An appendix to a footnote is the wrong place to introduce such a significant requirement. The Adequate Level of Reliability Task Force would be a more appropriate venue for this idea.
Tacoma Power City of Austin	No	We suggest removing section 2b "Assessment...health, safety..." for three reasons: 1)All outages have a negative impact on the community. Outages under footnote 12 do not inherently have more significant impact per MWhr lost than other outages allowed per Table 1. By requiring additional analysis for a similar societal impact, this provision discriminates against utilities at the fringes of the system. 2) While reminding planners to consider that their decisions do have real impacts to real people is a laudable goal, including this provision opens the door to significant legal liability and regulatory uncertainty. 3) An appendix to a footnote is the wrong place to introduce such a significant requirement. The Adequate Level of Reliability Task Force would be a more appropriate venue for this idea.
Response: The SDT understands the concerns and has clarified the wording accordingly. The intent of the SDT is that this action should be analogous to that required in approved EOP-001-2.1b. Section II, Bullet 2b. ~~Assessment~~ An explanation of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community		
Tri-State Generation & Transmission Association	No	In the NERC Glossary of Terms, Interruptible Demand is defined as "Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment." The process described in Attachment 1 creates an agreement between stakeholders (aka "end-use customers") and their transmission providers. Thus, if the process described in Attachment 1 is followed, the "Firm

Organization	Yes or No	Question 3 Comment
		Demand" referenced would be reclassified as "Interruptible Demand." In essence, "Footnote b" does not allow the interruption of Firm Demand. It merely requires that if interruption of Demand is required, it can only be Interruptible Demand. If this was the intention of FERC, NERC, and the Drafting Team, why didn't the drafting team just state "Interruption of Firm Demand is not allowed"?
Response: Upon reviewing the comments, the SDT has seen that a clarification for Demand that is not included as Firm Demand for footnote 'b' could be clarified as shown below. TPL-002-1c: footnote b) - ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load.		
Independent Electricity System Operator	No	No. The process presented in Section II is overly prescriptive. If a section that prescribes the information requirements for a stakeholder process is required, then for Canadian entities this section should simply state that any threshold should be established in a manner consistent with other service levels that apply to local transmission and retail service for the load to be curtailed.
Hydro One Networks Inc.	No	The process presented in Section II is overly prescriptive. If a section that prescribes the information requirements for a stakeholder process is required, then for non-US entities this section should simply require that the process information requirements must be in accordance with the requirements of the applicable Regulatory Authority or Governmental Authority or its delegated agency that is responsible for local transmission and retail service in that jurisdiction.
Response: Canadian entities are allowed to adopt ERO Reliability Standards, reject them outright, or adapt them for their own use within the confines of provincial regulations. Nothing has changed in that regard with this proposed standard. The effective date language covers the situation. No change made.		
Midwest Independent Transmission System Operator,	No	No. MISO objects to a stakeholder process as outlined in Attachment 1. See our

Organization	Yes or No	Question 3 Comment
Inc.		comments under Question 5.
Response: Please see response to question 5.		
Electric Reliability Council of Texas, Inc.	No	Please see ERCOT's response to question 1-the NERC Reliability Standards should not contain requirements related to stakeholder processes, whether they are procedural or substantive. If an exception process is retained, it should be outside of the NERC Reliability Standards (e.g. in the Rules of Procedure). To the extent the proposed standard inappropriately retains the stakeholder related aspects, ERCOT also provides the following comments on Section II-the ERCOT comments are in parentheses for easy reference and distinction relative to the proposed requirements.II. Information for Inclusion in Item #3 of the Stakeholder ProcessThe responsible entity shall document the planned use of Firm Demand interruption under footnote 'b' which must include the following: (ERCOT COMMENT: This is all that is needed for this. The documentation would be relative to the objective criteria developed for this purpose.) 1. Conditions under which Firm Demand interruption under footnote 'b' would be necessary:a. System Load level and estimated annual hours of exposure at or above that Load levelb. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency(ERCOT COMMENT: "1" is not necessary if objective criteria are developed as benchmarks for the exception process. In that case, exceptions would only be allowed if the objective criteria were met, regardless of the underlying assumptions related to conditions and contingencies.) 2. Amount of Firm Demand MW to be interrupted with:a. The estimated number and type of customers affectedb. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community(ERCOT COMMENT: The considerations reflected in a and b are inappropriate for a reliability standard. Appropriate considerations for reliability standards are related to the reliability performance of the system. The considerations in a and b are more akin to quality of service issues better suited for

Organization	Yes or No	Question 3 Comment
		regional policy discussions. It is not within the purview of the SDT to address those matters.) 3. Estimated frequency of Firm Demand interruption under footnote 'b' based on historicalPerformance (ERCOT COMMENT: Historical performance is irrelevant. If the SDT is going to retain revisions that accommodate non-consequential load shedding, then the only relevant metrics are the objective criteria that set the benchmarks for such exceptions.) 4. Expected duration of Firm Demand interruption under footnote 'b' based on historical performance(ERCOT COMMENT: See ERCOT response to "3" above.) 5. Future plans to mitigate the need for Firm Demand interruption under footnote 'b'(ERCOT COMMENT: This is redundant to the requirement in the reliability standards that requires a plan to resolve any violations identified in the planning process.Furthermore, if load shedding is allowed, this requirement doesn't make sense. Presumably the idea behind allowing these exceptions is to obviate the prospective need for other alternatives. If that is not the case, then there is no need to allow the exceptions, because the transmission upgrades to mitigate the need for load shedding can be established in the planning horizon.) 6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 'b'(ERCOT COMMENT: The basis for the load shedding exception is to provide a means to meet the TPL performance requirements in the context of a planning assessment. Accordingly, this is redundant to the planning assessments, the point of which is to identify and resolve performance issues.) 7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote 'b'(ERCOT COMMENT: Load shedding exceptions should be based on objective criteria and be reviewed pursuant to a process external to the NERC reliability standards. Alternative discussions could be part of that external process.)

Organization	Yes or No	Question 3 Comment
		8. Assessment of potential overlapping uses of footnote 'b' including overlaps with adjacent Transmission Planners and Planning Coordinators(ERCOT COMMENT: It is not clear what this means. Each functional entity performs assessments relative to its own system. This appears to introduce a vague regional transmission planning requirement with no structure or rules for such assessments.)
Response: Please see response to question 1. The SDT believes that the criteria in Section II are objective and represent the information that a stakeholder will want to see for assistance in determining their position on proposed planned actions. The SDT reminds the commenter that this process will involve some parties that are not experts in interpreting assessments and that these parties will need information that may be considered redundant or superfluous in other settings. Items such as historical performance would fall into this realm. No change made. The SDT has revised the language of bullet #5 due to other comments received. 5. Future plans to ~~mitigate~~ alleviate the need for Firm Demand interruption under footnote 'b' Bullet #8 does not introduce a regional planning requirement. It is consistent with Requirement R8 in proposed TPL-001-2a that mandate sharing of Planning Assessments. No change made.		
Xcel Energy	No	Section II should be left as part of the resolution in the dispute process and should not be made a requirement. Some in particular include:Â§ II.1. - this should be based only on applicable contingencies or conditions that could require NCLL. Having to include the estimated hours at or above a load level may not always be the most effective way to convey why NCLL will be used and adds little to the argument of why or why not it needs to be used. Â§ II.2.a - This may not always be apparent to the TO serving a wholesale transmission customers (REC, MUNICIPAL, etc.). This should be eliminated since it does little in emphasizing the need for NCLL. Â§ II.2.b - The "effect" of the use of NCLL may not always be apparent, because it is a perceived condition of what could happen that can be interpreted differently. I agree that it should be mentioned in the Stakeholder process outlining the locations

Organization	Yes or No	Question 3 Comment
		where NCLL will take place and let the dispute process identify and assess the health, safety and welfare of the community. How do you assess the effect in the Planning of NCLL. The effect should be identified by the party being affected and resolved in the dispute process. Â§ II.3 & 4. - This needs to be eliminated. Expected frequency and duration of NCLL based on historical performance DOES NOT GUARANTEE future performance and does little in emphasizing the need for NCLL. II.8 - This should be addressed by the Regional Planning Authority in their regional studies.
Response: The SDT disagrees and believes that the criteria in Section II represent the information that a stakeholder will want to see for assistance in determining their position on proposed planned actions. The SDT reminds the commenter that this process will involve some parties that are not experts in interpreting assessments and that these parties will need information that may be considered redundant or superfluous in other settings. Items such as historical performance would fall into this realm. No change made.		
ISO New England	No	Section II, 2.a states that studies must address the estimated number and type of customers affected by Non-Consequential Load Shedding. This language should be removed for three reasons.(1) This appears to be inappropriate for a reliability standard. The specific number and type of customers within a set number of MWs that are electrically acceptable do not impact the reliability of the bulk electric system (as defined by Section 215 of the Federal Power Act). (2) Even if the number and type of affected customers were an appropriate process question for an ERO standard, the number and type of customers may change depending on particular system configuration at the time of the load shedding. For example, a substation may be reconfigured to address other system issues such as maintenance and a certain number of MWs of load being interrupted, while still electrically acceptable from a system reliability perspective, may impact different numbers and types of customers. (3) Assuming that the number and type of customers affected were an appropriate metric, the Transmission Planner in many cases will not be the

Organization	Yes or No	Question 3 Comment
		appropriate entity to address these concerns. The Transmission Owner, Distribution Provider or Load Serving Entities would be the appropriate entities to address customer affects. Section II, 2.b should be revised to delete the reference to "health, safety, and welfare of the community." It is inappropriate for a NERC Standard to require planners to address the "health, safety, and welfare of the community." NERC's authority appears limited to regulating the "reliability" of the bulk electric system. Section 215 specifies that NERC's authority it to establish Reliability Standards necessary to ensure an "adequate level of reliability." Reliability Standards may specify the "design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation." Section 215 defines "reliable operation" as "operating the elements of the BPS within equipment and electrical system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements." Establishing this requirement is also arbitrary, because it is inconsistent with other transmission planning requirements. For example, the same load could be shed directly as the consequence of a fault and no such assessment is required. In addition, Transmission Planners can plan for the shedding of radial load with no assessment of health, safety and welfare. Section II, requirements 3 and 4 discuss estimating frequency and duration of Non-Consequential Load Loss based on historical performance. This provision is inconsistent with the manner in which transmission system planning is conducted and should be removed. The transmission system planning process uses deterministic not probabilistic assessments. While a power system may utilize these factors in assessing where the use of non-consequential load loss may be acceptable in terms of providing service, these factors do not inform reliability risks to the bulk electric system where the loss of load is found to be electrically acceptable in terms of system reliability (i.e., no thermal, voltage, or stability issues are created or

Organization	Yes or No	Question 3 Comment
		exacerbated and no instability, uncontrolled separation, or cascading failures result).
Response: The SDT believes that the criteria in Section II represent the information that a stakeholder will want to see for assistance in determining their position on proposed planned actions. The SDT reminds the commenter that this process will involve some parties that are not experts in interpreting assessments and that these parties will need information that may be considered redundant or superfluous in other settings. Items such as historical performance would fall into this realm. No change made. The SDT understands the concerns and has clarified the wording. The intent of the SDT is that this action should be analogous to that required in approved EOP-001-2.1b. Section II, Bullet 2b. ~~Assessment~~ An explanation of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community The SDT believes that the criteria in Section II represent the information that a stakeholder will want to see for assistance in determining their position on proposed planned actions. The SDT reminds the commenter that this process will involve some parties that are not experts in interpreting assessments and that these parties will need information that may be considered redundant or superfluous in other settings. Items such as historical performance would fall into this realm. No change made.		
SCE&G	No	We believe that item 1.b of Section II may contain Critical Energy Infrastructure Information (CEII) and should have limited distribution. The appropriate non-disclosure agreements would be required in order to prevent widespread publication of the information.
SERC EC Planning Standards Subcommittee Associated Electric Cooperative	No	We believe that item 1.b of Section II would contain CEII information and should have limited distribution. The appropriate non-disclosure agreements would need to be developed to prevent widespread publication of the information.
Response: If an entity believes that CEII information is involved then the entity should use the appropriate mechanisms to protect that information while still providing the basics of the information needed for the process to continue. No change made.		
NBSO	No	We do not agree with the need for Section II (and Attachment I as a whole) at all. The footnote, or Attachment I, should only stipulate that when Non-Consequential Load Loss is needed to ensure that BES performance requirements are met, then

Organization	Yes or No	Question 3 Comment
		regulatory approval from local jurisdiction needs to be provided with demonstration that the approval was obtained through an open stakeholder process.
Response: The SDT believes that the criteria in Section II represent the information that a stakeholder will want to see for assistance in determining their position on proposed planned actions. The SDT reminds the commenter that this process will involve some parties that are not experts in interpreting assessments and that these parties will need information that may be considered redundant or superfluous in other settings. Items such as historical performance would fall into this realm. No change made.		
LCRA Transmission Service Corporation	No	
NB Power Transmission	No	
Response: Without specific comments, the SDT is unable to respond.		
Texas Reliability Entity	Yes	In Section II, part 1b, TRE suggests replacing ‘applicable rating’ with ‘steady state performance requirments’, to account for all the BES performance requirements (in particular, steady-state and post-contingency voltages) for which the footnote may be utilized.
Response: Applicable ratings are the basis for the performance requirements in Table 1 of proposed TPL-001-2a. Therefore, the SDT believes that the existing terminology correctly addresses the performance issue. No change made.		
Southwest Power Pool Reliability Standards Development Team	Yes	In this section the reference to Customers should only be Customers of Transmission and not open ended for any customer. Once it is sold wholesale the TP wouldn’t know where it is being sent to. We would also note that under some jurisdictions that there is a minimum duration threshold for keeping historical data on some of these events that are being requested under this section. Need to add language to accommodate these thresholds so as not to contradict what is being asked for by the regulatory bodies.
Response: The SDT disagrees that the only customers that should be considered are wholesale customers. The total number of		

Organization	Yes or No	Question 3 Comment
customers affected is information that helps other stakeholders understand the full impact of the planned usage of footnote 'b'. The SDT also disagrees that the Transmission Planner will not know where the Load will be lost. The Transmission Planner cannot evaluate the impacts of interrupting Firm Demand without knowing where the Load is connected to the BES system. The historical information is not related to historical planned Load interruption, but rather the historical performance of similar Facilities. However, If an entity does not have its own historical information available then it should use other available data to make its best estimate of what the values will be. No change made.		
New England States Committee on Electricity (NESCOE)	Yes	NESCOE agrees with the list provided in Section II. Regarding item #7, in the interest of explicit direction, NESCOE suggests adding at the end of the sentence the following language: "and cost comparisons of all alternatives."
Response: Cost considerations will be part of a rationale for selection or non-selection of an alternative. The SDT believes the current terminology captures this concept. No change made.		
Ameren	Yes	We believe that item 1b of Section II would contain critical electric infrastructure information (CEII) and should have limited distribution. The appropriate non-disclosure agreements would need to be developed to prevent widespread publication of the material.
Response: If an entity believes that CEII information is involved then the entity should use the appropriate mechanisms to protect that information while still providing the basics of the information needed for the process to continue. No change made.		
Duke Energy	Yes	
Florida Municipal Power Agency Lakeland Electric Gainesville Regional Utilities	Yes	
Southern Company	Yes	

Organization	Yes or No	Question 3 Comment
Western Area Power Administration	Yes	
American Electric Power	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Deseret Generation & Transmission	Yes	
Platte River Power Authority	Yes	
Massachusetts Attorney General	Yes	
California Independent System Operator	Yes	
Public Service Company of New Mexico	Yes	
Idaho Power Company	Yes	
Georgia Transmission Corp	Yes	
Modesto Irrigation District	Yes	
Response: Thank you for your support.		

4. **Do you agree with the text in Section III of Attachment 1? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The majority of the comments received here are similar to those submitted for question 1 and similar responses have been provided.

The following clarifying changes were made due to industry comments:

TPL-002-1c: footnote b) - ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load.

Attachment 1, Section III, first paragraph: Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ~~assure~~ ensure that the applicable regulatory ~~authority~~ authorities or governing ~~body~~bodies responsible for retail electric service issues do~~es~~ not object to the use of Firm Demand interruption under footnote 'b' if either:

Attachment 1, Section III, last paragraph: Once assurance has been received that the applicable regulatory ~~authority~~ authorities or governing ~~body~~bodies responsible for retail electric service issues do~~es~~ not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.

Organization	Yes or No	Question 4 Comment
Public Utility District No.1 of Snohomish County MEAG Power City of Austin Clark Public Utilities	No	1) Similar to our comment on question 2, please remove the words "as an element of a Corrective Action Plan" from the first sentence. There are cases on the fringes of the system where Non-Consequential Load Loss is the preferred alternative in both the long term and short term, not as a temporary patch. Since a Corrective Action Plan is a "list of actions and an associated timetable for implementation to remedy a specific problem," using this term removes the stakeholders ability to evaluate the costs and benefits and instead requires them to treat this a problem where the only solution is building new facilities.

Organization	Yes or No	Question 4 Comment
		2) For any specific use of footnote b, there could be several applicable regulatory authorities such as small municipalities or public utility districts. The standard should clarify whether the planner must show evidence that every authority did not object, or whether the planner only needs to show that less that 25 MW was not rejected by the regulatory authorities. To accomplish this clarification, we propose: A) In Section III paragraph 1 and paragraph 5 change “regulatory authority or governing body” to “regulatory authorities or governing bodies.” B) Add a sentence to bullet 2 to read “If multiple regulatory authorities or governing bodies are responsible for retail electric service issues, only the portion of Non-Consequential Load Loss exceeding 25 MW is subject to section III.”
Tacoma Power	No	1) Similar to our comment on question 2, please remove the words “as an element of a Corrective Action Plan” from the first sentence. There are cases on the fringes of the system where Non-Consequential Load Loss is the preferred alternative in both the long term and short term, not as a temporary patch. Since a Corrective Action Plan is a “list of actions and an associated timetable for implementation to remedy a specific problem,” using this term removes the stakeholders ability to evaluate the costs and benefits and instead requires them to treat this a problem where the only solution is building new facilities. 2) For any specific use of footnote b, there could be several applicable regulatory authorities such as small municipalities or public utility districts. The standard should clarify whether the planner must show evidence that every authority did not object, or whether the planner only needs to show that less that 25 MW was not rejected by the regulatory authorities. To accomplish this clarification, we propose: A) In Section III paragraph 1 and paragraph 5 change “regulatory authority or governing body” to “regulatory authorities or governing bodies.” B) Add a sentence to bullet 2 to read “If multiple regulatory authorities or governing bodies are responsible for retail electric service issues, only the portion of Non-Consequential Load Loss exceeding 25 MW is subject to section III.”

Organization	Yes or No	Question 4 Comment
Response: (1) The SDT disagrees. When alternatives and the rationale for selection or non-selection of those alternatives are presented, cost factors can certainly be part of the rationale. In proposed TPL-001-2a, Requirement R2, Part 2.7.1, a list of possible actions that could be included in a Corrective Action Plan is provided. This list shows several alternatives that do not require the building of new Facilities. No change made. (2) The SDT agrees that the plural use of the terms shown in A) above should be consistent throughout the document and has made corresponding changes to reflect this. The SDT does not agree with the proposed change shown in B). The footnote is applicable for a single Contingency and ownership or jurisdictional concerns do not come into play. The total value of Load affected by the single Contingency is the correct value to determine if the situation is subject to Section III. Attachment 1, Section III, first paragraph: Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ~~assure~~ ensure that the applicable regulatory ~~authority~~ authorities or governing ~~body~~bodies responsible for retail electric service issues do~~es~~ not object to the use of Firm Demand interruption under footnote 'b' if either: Attachment 1, Section III, last paragraph: Once assurance has been received that the applicable regulatory ~~authority~~ authorities or governing ~~body~~bodies responsible for retail electric service issues do~~es~~ not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.		
MRO NSRF USACE	No	(1) In Attachment 1 Section III, what is the definition of "applicable regulatory authority or governing body"? Is this the state PSC or PUC? Is it the Regional Reliability Organization (RRO)? Is it the Reliability Coordinator (RC)? RECOMMENDATION: Depending on the answer to the above question, define "applicable regulatory authority or governing body" more precisely. The language could read "applicable regulatory authority or governing body responsible for retail electric service such as the state Public Services Commission or Public Utilities Commission". A less vague statement allows the important parties to be included in every instance Attachment 1 is used. (2) In Attachment 1, if non-consequential load loss is planned at multiple bulk delivery points to mitigate the same contingency should the total load loss count

Organization	Yes or No	Question 4 Comment
		towards the 25 MW and 75 MW thresholds or should the loads be counted individually? EXAMPLE: There are two load serving substations (X load at substation B and Y load at substation C) on a long 115 kV line with 230/115 kV transformation at each end (substation A and substation D). Automatic under-voltage load shedding is in place at substations B and C, the UVLS relays at each substation making load trip decisions based on local voltage (i.e. independent operation). If one end of the 115 kV line trips and 115 kV voltage is below allowable levels at both substations X and Y, then the total load tripped by UVLS will be X+Y. Does the X+Y value count towards the 25 MW and 75 MW thresholds or are X and Y counted separately? What if X load is dropped for one contingency and Y load is dropped for a different contingency, is the total load counted X+Y or each load separately? RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote 'b' could read "In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for any single contingency." Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion. (3) If non-consequential load loss is planned at multiple bulk delivery points in close proximity to mitigate different contingencies should the total load loss count towards the 25 MW and 75 MW thresholds or should the loads be compared individually? For example, there are two load serving substations (X load at substation B and Y load at substation C) on a networked 115 kV line with 230/115 kV transformation at both ends (substation A and substation D). Automatic under-voltage load shedding is in place at substations B and C that would trip X amount of load if one end of the 115 kV line tripped and 115 kV voltage was below allowable levels, and would trip Y amount of load if the other end of the 115 kV line tripped and 115 kV voltage was below allowable levels. Does the X+Y value count towards the 25 MW and 75 MW thresholds or are X and Y counted separately? In addition to the aforementioned contingencies, if the 115 kV line between substations B and C opens, both loads X and Y will trip. Now does the X+Y value count towards the 25

Organization	Yes or No	Question 4 Comment
		MW and 75 MW thresholds? (4) In Attachment 1, if UVLS relaying is programmed at a sub to trip the load in stages at multiple voltage setpoints, such that only a fraction of the load is tripped for a given contingency, is the entirety of the load still counted towards the 25 MW and 75 MW thresholds? EXAMPLE: Substation B has X load that will trip if the BES voltage gets to 0.92 p.u. and Y that will trip if the BES voltage gets to 0.88 p.u. If only X amount of load is required to mitigate a single contingency in the near-term TPL assessment, is X load counted towards the 25 MW and 75 MW thresholds or is X+Y load counted? Is there a difference if the Y load is at a different, nearby substation with both loads having the aforementioned tripping logic? RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote 'b' could read "In no case can the planned Firm Demand interruption under footnote 'b' (as demonstrated in the near-term horizon analysis) exceed 75 MW." Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion
Minnkota Power Cooperative Otter Tail Power Company	No	1. MPC QUESTION: In Attachment 1 Section III, what is the definition of "applicable regulatory authority or governing body"? a. Is this the state Public Service Commission or Public Utilities Commission, the Regional Reliability Organization (RRO), and/or the Reliability Coordinator (RC)? b. RECOMMENDATION: Depending on the answer to the above question, define "applicable regulatory authority or governing body" more precisely. The language could read "applicable regulatory authority or governing body responsible for retail electric service such as the state Public Services Commission or Public Utilities Commission". A clearly defined statement allows the Transmission Planner and Planning Coordinator to identify the appropriate parties to be included in every instance Attachment 1 is used. 2. MPC QUESTION: In Attachment 1, if non-consequential load loss is planned at multiple bulk delivery points to mitigate the same contingency should the total load loss count towards the 25 MW and 75 MW thresholds or should the loads be

Organization	Yes or No	Question 4 Comment
		counted individually? a. EXAMPLE: There are two load serving substations (X load at substation B and Y load at substation C) on a long 115 kV line with 230/115 kV transformation at each end (substation A and substation D). Automatic under-voltage load shedding is in place at substations B and C, the UVLS relays at each substation making load trip decisions based on local voltage (i.e. independent operation). If one end of the 115 kV line trips and 115 kV voltage is below allowable levels at both substations X and Y, then the total load tripped by UVLS will be X+Y. i. Does the X+Y value count towards the 25 MW and 75 MW thresholds or are X and Y counted separately? ii. What if X load is dropped for one contingency and Y load is dropped for a different contingency, is the total load counted X+Y or each load separately? b. RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote ‘b’ could read “In no case can the planned Firm Demand interruption under footnote ‘b’ exceed 75 MW for any single contingency.” Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This clarification would explain much more clearly what is counted towards the two thresholds and decrease confusion. 3. MPC QUESTION: In Attachment 1, if UVLS relaying is programmed at a sub to trip the load in stages at multiple voltage setpoints, such that only a fraction of the load is tripped for a given contingency, is the entirety of the load still counted towards the 25 MW and 75 MW thresholds? a. EXAMPLE: Substation B has X load that will trip if the BES voltage gets to 0.92 p.u. and Y that will trip if the BES voltage gets to 0.88 p.u. i. If only X amount of load is required to mitigate a single contingency in the near-term TPL assessment, is X load counted towards the 25 MW and 75 MW thresholds or is X+Y load counted? ii. Is there a difference if the Y load is at a different, nearby substation with both loads having the aforementioned tripping logic? b. RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote ‘b’ could read “In no case can the planned Firm Demand interruption under footnote ‘b’ (as demonstrated in the near-term horizon analysis) exceed 75 MW at a single substation.” Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain

Organization	Yes or No	Question 4 Comment
		much more clearly what is counted towards the two thresholds and decrease confusion.
Response: (1) The SDT believes that any attempt to more specifically enumerate regulatory bodies will result in the exact opposite effect of what is stated in that inevitably there will be a one-off situation that doesn't fit the statement. The SDT believes that the entity will know who needs to be involved and will take the appropriate steps to make certain that the correct parties are involved. No change made. (2) Footnote 'b' only applies to single Contingencies so the SDT believes that adding the suggested words would be redundant. In the specific example cited, if the actions taken are the result of the same single Contingency, then the total value of the Load shed would be applicable. No change made. (3) If the Load shed is the result of different Contingencies, the proximity doesn't matter and the Load would be counted separately. (4) The SDT believes that the suggested wording would be redundant. Only Load shed due to a single Contingency is applicable here. No change made.		
ACES Power Marketing Standards Collaborators	No	(1) We disagree with the threshold of 75 MW, as mentioned above.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made.		
Southern California Edison Company	No	As applied to SCE's service territory, Section III of Attachment 1 appears to require written acknowledgement and approval by the CPUC of each and every Firm Demand interruption authorized by the CAISO's annual transmission plan. In California, the CPUC is notified of and invited to every CAISO meeting on transmission planning, but the CPUC generally does not provide specific written assurances or agreement on detailed elements of the CAISO transmission plan. SCE believes that a general approval of the overall plan from the regulatory body should

Organization	Yes or No	Question 4 Comment
		be adequate.
Response: The SDT disagrees that formal approval is required for every instance of Firm Demand interruption as Section III only applies for Load over 25 MW. Obtaining assurance from regulators that they do not object will undoubtedly occur in different ways. Some regulators may provide written assurances or agreement but that is not required by the standard. No change made.		
Bonneville Power Administration	No	For use of Non-Consequential Load Loss in Year One of the Planning Assessment, BPA believes that assurance received from the applicable regulatory authority or governing body responsible for retail electric service issues is adequate and submission to the ERO for a determination of adverse impact is unnecessary. The local utility and regulators are better positioned to determine adverse impacts on an individual system, whereas the ERO would have to develop a process and criteria for assessing adverse impacts.
Response: The remand Order made it clear that oversight was required for instances where use of footnote 'b' was proposed. The ERO is aware of the proposed responsibility and has accepted this role if the industry approves. No change made.		
Tri-State Generation & Transmission Association	No	How would section III of "Attachment 1" be applied to entities that only deliver wholesale electric service and no retail electric service?
Response: The SDT believes that the wholesale customer will be one of the stakeholders included in the process and any use of the footnote must go through the stakeholder process. No change made.		
Modesto Irrigation District	No	I am voting NO because there is no technical basis for use of the 75 and 25 MW absolute threshold values, regardless of the size of the utility's load, referenced in the proposed standard. WECC's past experience with implementation of arbitrary magnitudes for requirements (e.g., the 5% and 7% arbitrary magnitude contingency reserve requirements), has proved to be problematic. I would suggest investigating a technical basis for using a relative requirement, such as percentage of the utility's load, maybe 5% and 2.5%, respectively, and that it be based on technical requirements similar to those found in Table 1 of the WECC Criteria TPL-001-WECC-

Organization	Yes or No	Question 4 Comment
		CRT-2.Thank you.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. Utilizing a percentage of an entity's Load may be problematic – when dealing with a small entity it could be a small value but still of rather large import and if dealing with a large entity could result in significant amounts of Load shed being planned. And, the FERC Order states that a percentage approach would not be appropriate for the aforementioned reasons. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made.		
Electric Reliability Council of Texas, Inc.	No	If non-consequential load shedding is allowed for single contingency conditions, as discussed above, it should be based on objective critieria. As such, there is no need for the proposed stakeholder process, including the Section Ill instances requiring regulatory review. Furthermore, establishing approval roles in planning processes for entities other than the relevant functional entities conflicts with the appropriate roles, and appropriate separation of those roles, of the relevant entities (i.e. the planning authority and the state regulatory body and NERC RE). Typically a functional entity performs the functional activity, and others relevant to the proposed process in the standard perform compliance and regulatory oversight of the functional performance. This is a practical concern, and also potentially raises conflicts between governing authorities that create the separation of roles, where, typically, the relevant authorities establish a functional entity as the planning entity, and NERC and its REs and state regulators (as relevant - e.g. in ERCOT) are charged with compliance and regulatory oversight. As with the other stakeholder process sections, that section should be eliminated.
Response: The SDT used the Board of Trustees approved standard as a starting point for this draft. FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted		

Organization	Yes or No	Question 4 Comment
draft added detail and specificity to the already approved approach. No change made. The SDT believes that the role provided to regulatory bodies is consistent with current practices in the industry today. While formal approval may not be provided by some regulatory bodies as pointed out in other comments, Section III does not require formal approval but rather a lack of dissent. No change made.		
National Association of Regulatory Utility Commissioners	No	It appears that the 25 MW minimum value is merely a reflection of antidotal information from a small number of data request responders and as such is not technically justified. NARUC is not poised to offer an alternative; given that the State/local regulator is consulted in this process, States should be appraised if any load is anticipated to be shed under any planning criteria. Thus, no mimimum value should be set.
Response: The data request is not anecdotal information. All of the Transmission Planners in the continental United States supplied their data in response to the data request. The SDT believes it is unrealistic to consider the allowable usage of footnote 'b' in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. Absent any alternative suggestion and given the participation of appropriate regulatory bodies in both Sections I and III, the SDT believes that the current threshold is the best possible solution. No change made.		
Xcel Energy	No	It does not appear that an entity has any options if the applicable regulatory authority or governing body objects to the use of NCLL in year one. This could potentially occur as a result of load patterns and generation issues submitted by an LSE not necessarily having BES elements and the only solution is to implement NCLL. In year one, it is too late to build any necessary and NCLL may be the only alternative.
Response: While the requirement is not mandatory until Year One, the SDT believes that it would be a good practice to move forward as soon as an entity knows it is contemplating usage of the footnote. That way, alternatives can be openly discussed before time becomes an overriding concern. The instance described above points to the need for the stakeholder process as this process will facilitate closer coordination with the Load-Serving Entities providing the information and the applicable regulators. No change made.		

Organization	Yes or No	Question 4 Comment
MidAmerican Energy Company	No	Item III of Attachment I should be deleted completely. Non ERO regulatory review is not necessary. Applicable regulatory authority or governing bodies responsible for retail electric service issues are stakeholders which may participate in the stakeholder process. Further, there are concerns compliance may not be possible because item III makes non-NERC applicable regulatory authorities or governing bodies responsible for retail electric service issues part of a NERC mandatory compliance without consequence to the said non-NERC governing bodies. Non-NERC entities are not constrained by NERC mandatory laws and penalties and aren't compelled to perform actions to meet NERC compliance. This opens a risk to any NERC regulated entities governed by such regulatory or governing bodies that do not or may not feel compelled to have a process for the NERC regulatory review specified in item III of attachment I.
Response: The SDT believes that the role provided to regulatory bodies is consistent with current practices in the industry today. While formal approval may not be provided by some regulatory bodies as pointed out in other comments, Section III does not require formal approval but rather a lack of dissent. No change made.		
New England States Committee on Electricity (NESCOE)	No	NESCOE is concerned that the 25 MW minimum value for regulatory review lacks sufficient technical justification. NESCOE understands that the SDT used responses to data requests to establish this 25 MW value, which is based on the average number of MWs that entities applying footnote “b” reported using in transmission planning. This may be a good starting point, but additional analysis is warranted. Specifically, the analysis should consider a more direct nexus to the system, such as substation design criteria. Additionally, as detailed above, Attachment 1 should provide clarity regarding the meaning of “applicable regulatory authorities.” Moreover, clarification is required regarding the initial triggering factor for regulatory review. Section III states that the regulatory review process is required before the footnote can be utilized in “Year One” of the planning horizon. Does this mean that such regulatory review only applies to year one or does it apply to year one and beyond?

Organization	Yes or No	Question 4 Comment
		If the former, NERC needs to provide a clear rationale for restricting such review when limiting factors are already applied (i.e., voltages greater than 300 kV or a 25 MW minimum threshold value).
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote ‘b’ by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote ‘b’. Other considerations can be a point of reference or sanity check but in and of themselves are not sufficient for setting a threshold in this matter. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach and that no further research is required. No change made. The SDT believes that any attempt to more specifically enumerate regulatory bodies will result in the exact opposite effect of what is stated in that inevitably there will be a one-off situation that doesn’t fit the statement. The SDT believes that the entity will know who needs to be involved and will take the appropriate steps to make certain that the correct parties are involved. The only mandated trigger for review is the need to have met the stipulations of the footnote and attachment prior to utilizing Load shed for single Contingencies in a Corrective Action Plan in Year One. While the requirement is not mandatory until Year One, the SDT believes that it would be a good practice to move forward as soon as an entity knows it is contemplating usage of the footnote. That way, alternatives can be openly discussed before time becomes an overriding concern. No change made. As stated, the review is only required prior to utilizing the footnote in a Corrective Action Plan in Year One. The SDT believes this terminology is clear and understood. No change made.		
Independent Electricity System Operator	No	No. The process presented in Section III is overly prescriptive and requires information not necessary to the intended purpose.As state in Q1, we disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard, and propose alternate language as stated in Q1 comments.If this section must deal with a review of the use of footnote ‘b’/’12’ to ensure that there are no adverse reliability impacts on the bulk power system, then it should be limited to the information required for that purpose. Provided there is local support for the use of Non-Consequential Load Loss under footnote ‘b’/’12’, only information items 6 and 8 from section II are relevant for this assessment-the remainder are not required for this section and should be deleted.

Organization	Yes or No	Question 4 Comment
		As stated in Q2 above, the use of footnote ‘b’/’12’ shouldn not be limited to the Near-Term Planning Horizon. We propose that the words “in Year One of the Planning Assesssment”be deleted.Items 1 and 2 complicate this section and are unneccesary. They should be replaced by a phrase such as “for those planning events where the use of footnote ‘b’/’12’ is referenced”. We disagree with the need to submit to the ERO for a determination of whether there are any adverse reliability impacts caused by the use of Non-Consequential Load Loss. This will introduce a new type of review at the ERO that will create uneccesary delays and burden, and is inconsistent with and not required for all of the other performance requirements in the TPL standards. Submitting the analysis to the adjacent Planning Coordinators and Tranmission Planners, and any functional entity that requests it, as called for in requirement R8 of TPL001-2 should be sufficient.
Response: Please see the response to question 1. Please see the response to question 2. The remand Order made it clear that oversight was required for instances where use of footnote ‘b’ was proposed. The ERO is aware of the proposed responsibility and has accepted this role if the industry approves. The SDT believes that Requirement R8 of proposed TPL-001-2a is an important concept for sharing information and potentially resolving local differences, but it does not necessarily provide the wider area view that the ERO could provide. No change made.		
Midwest Independent Transmission System Operator, Inc.	No	No. MISO objects to a stakeholder process as outlined in Attachment 1. See our comments under Question 5.
Response: Please see response to question 5.		
Southwest Power Pool Reliability Standards Development Team	No	Section III is superfluous if the regulatory bodies are attending the open stakeholder process. This section should be removed due to the fact that if there is an issue or question on these events they should be addressed in the open stakeholder

Organization	Yes or No	Question 4 Comment
		meeting. Not sure why the team decided to add the ERO as an entity to check after the regulatory body has approved the use. We feel like if there needs to bee coordination between affected entities that they could participate in the open stakeholder process as well. You could add that they include possible affected entities to the invite list of the open meeting to discuss these footnote applications under section 1.
Response: The invitees to the stakeholder process should include all applicable entities and would be expected to include applicable regulatory bodies as shown. However, there is existing protocol for relationships between functional entities and regulatory bodies that goes beyond the extent of Section I and that is out of the purview of the SDT. That difference as well as the difference in Load levels between Sections I and III is what drove the SDT to produce the draft as posted. No change made. The remand Order made it clear that oversight was required for instances where use of footnote ‘b’ was proposed. The ERO is aware of the proposed responsibility and has accepted this role if the industry approves. No change made. The invitees to the stakeholder process should include all applicable entities and would be expected to include applicable regulatory bodies as shown. However, there is existing protocol for relationships between functional entities and regulatory bodies that goes beyond the extent of Section I and that is out of the purview of the SDT. That difference as well as the difference in Load levels between Sections I and III is what drove the SDT to produce the draft as posted. No change made.		
Western Area Power Administration	No	See answer to Question 1.
Platte River Power Authority	No	See answer to Question 1.
Florida Municipal Power Agency Lakeland Electric Gainesville Regional Utilities	No	See FMPA Comments regarding the 75 MW threshold of Question 1.

Organization	Yes or No	Question 4 Comment
Response: Please see response to question 1.		
NBSO	No	See our comments under Q2 and Q3, above.
Response: Please see responses to questions 2 and 3.		
Massachusetts Attorney General	No	The 75 MW and 25 MW limits do not belong there. It would be best if the limits were established by stakeholder consensus and by state rulemakings.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made.		
National Grid	No	The current document includes the language: 2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW.This gives no concept of how long customers could expect to be out of service and hence whether this would be an appropriate approach. Suggest using a value that is based on energy, i.e., MWh. A value of 600MWh would represent 25 MW out for 24 hours, or could be 60 MW out for 10 hours, etc. This would seem to provide a more valuable understanding the true impact to customers in assessing the health, safety and welfare. It is also expected that if Demand Resources are being used that they would be excluded from the term "non-consequencial" load, and that the value being discussed is only that in addition to any Demand Resources being used.
Response: The Section 1600 data request showed that entities were reporting footnote 'b' usage strictly in terms of MW. Therefore, the SDT decided to stay with existing terminology in this regard. In addition, duration is one of the factors required in Section II so the time element will be known to process participants. No change made. Upon reviewing the comments, the SDT has seen that Demand that is not included as Firm Demand for footnote 'b' could be clarified		

Organization	Yes or No	Question 4 Comment
as shown below. TPL-002-1c: footnote b) - ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load.		
Hydro One Networks Inc.	No	The process presented in Section III is overly prescriptive and duplicates information not necessary for its intended purpose.As stated in Q1, we disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard, and propose alternate language in our response to Q1.If this section is required to address a review of the use of footnote 12 to ensure that there are no wide-spread adverse reliability impacts on the bulk power system, then it should be limited to the information required for that purpose. Provided there is local support for the use of Non-Consequential Load Loss under footnote 12, only information items 6 and 8 from section II are relevant for this assessment-the remainder are not required for this section and should be deleted. Items 1 and 2 complicate this section and are unneccesary. They should be replaced by a phrase such as “for those planning events where the use of footnote 12 is referenced.” We disagree with the need to submit this information to the ERO for a determination of whether there are any Adverse Reliability impacts caused by the use of Non-Consequential Load Loss. This will introduce a new type of review at the ERO that will create uneccesary delays and burden, and is inconsistent with (and not required for) all of the other performance requirements in the TPL standards. Submitting the analysis to the adjacent Planning Coordinators and Tranmission Planners, and any functional entity that requests it, as called for in requirement R8 of TPL-001-2 should be sufficient.
Response: Please see the response to question 1. Items 1 and 2 place the constraints in the process that separate the less restrictive procedure outlined in Section I from the more		

Organization	Yes or No	Question 4 Comment
restrictive procedure in Section III. The suggested change would require the same level of review for any use of the footnote. The SDT does not believe that this is where the industry wants to go based on comments received. No change made. The remand Order made it clear that oversight was required for instances where use of footnote 'b' was proposed. The ERO is aware of the proposed responsibility and has accepted this role if the industry approves. Therefore, the SDT believes that there will not be any undue delays. The SDT believes that Requirement R8 of proposed TPL-001-2a is an important concept for sharing information and potentially resolving local differences, but it does not necessarily provide the wider area view that the ERO could provide. No change made.		
Ameren	No	The responses to the data request indicate that 33% of the respondents that use footnote "b" would drop 20 MW or less for single contingency events. Based on the data, we believe that the threshold for reporting should be 20 MW instead of 25 MW. As noted above in the response to item 1, we also believe that an upper limit of 40 MW should be established, again based on the responses to the data request. We find this proposed stakeholder process unique because we are inviting retail regulatory authorities to become involved in the compliance process for a handful of utilities now, but potentially for more in the future. We are unaware of any other standards where a state governmental agency is needed to grant permission for utilities to utilize certain aspects of the standard. We believe that this proposed process would potentially set a bad precedent, is not good policy for either the regulators or the transmission planners, and does not belong in a NERC standard.
Response: The SDT believes that the threshold selected is consistent with the data supplied in the data request within reasonable limits. No change made. Please see response to question 1. The SDT believes that the role provided to regulatory bodies is consistent with current practices in the industry today. While formal approval may not be provided by some regulatory bodies as pointed out in other comments, Section III does not require formal approval but rather a lack of dissent. No change made.		

Organization	Yes or No	Question 4 Comment
Arizona Public Service Company	No	The threshold of 25 MW in item 2 of section III is too low. It should be same as the maximum allowed value in foot note b. In addition, AZPS does not agree that no objection assurance by the Regional Entity should be required. Once the process has been fully vetted by the stakeholders, including the regulatory authority for retail service, there is absolutely no need for Regional Entity involvement. There would be no adverse affect of non-consequential load tripping on the BES. Hence no reason for Regional Entity involvement is needed.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a least common denominator approach and would thus be rejected. No change made. The remand Order made it clear that oversight was required for instances where use of footnote 'b' was proposed. The ERO has been proposed as the best choice to provide such oversight. No change made.		
Manitoba Hydro	No	The word 'assure' should be 'ensure' in the opening paragraph of III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required.
Response: The SDT agrees and has made the change suggested. Section III, first paragraph: Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ~~assure~~ ensure that the applicable regulatory ~~authority~~ authorities or governing ~~body~~bodies responsible for retail electric service issues do~~es~~ not object to the use of Firm Demand interruption under footnote 'b' if either:		
ISO New England	No	This provision violates both the federal and state jurisdictional split over transmission facilities, and would violate several FERC orders directing the

Organization	Yes or No	Question 4 Comment
		independence of RTOs in the regional system planning process. Said another way, the determinations of a federal transmission planning entity may not be required through an ERO standard to be subject to non-jurisdictional review and approval by state entities. Further, the provision violates Section 215 of the Federal Power Act, as the ERO cannot require the review of a particular transmission system plan by state entities. The following language should therefore be deleted from Section III of Attachment 1: "Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Non-Consequential Load Loss under footnote 12... ." Overall, the order of Section III is also notable. During year, two through ten of the overall planning horizon the standard allows for Non-Consequential Load Loss without state approval. In the first year of the assessment, approval becomes required for Non-Consequential Load Loss. In year one, even if mandating state participation and decisional authority in a federal planning process was legally permissible, it is too late to allow for any other alternative as transmission planning, siting and construction of non-load loss alternatives would not be completed in the needed period. If there were non-load loss alternatives available, the use of non-consequential load loss would not be necessary, but it would also not be part of a transmission plan. The Regional Entities with NERC oversight perform periodic audits and require self-certification of the planning process. By virtue of the audit and self-certification process, NERC has the ability to monitor the use of Non-Consequential Load Loss in planning assessments. In addition to being notable for the year one timing, Section III seems incomplete. In the case where there is objection to Non-Consequential Load Shedding, the process appears to end without resolution. The submission to the ERO "for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss" conflcts with

Organization	Yes or No	Question 4 Comment
		federal law and orders of the Federal Energy Regulatory Commission. As noted above, the ERO is not a planning entity and does not have authority to displace the reliability planning performed by planning entities. Transmission planning entities are those directed by FERC to make the determinations regarding adverse reliability impacts. If any entity wishes to challenge those determinations, it may do so before FERC under Section 215 of the Federal Power Act. Further, this provision would conflict with orders of the FERC regarding the independence of RTOs to conduct the regional transmission planning process. A reliability standard may not change the scope or meaning of federal statutes nor may it contradict or collaterally attack orders of the Federal Energy Regulatory Commission. For these reasons, this provision should be removed from the attachment to the proposed standard.
Response: The SDT believes that the role provided to regulatory bodies is consistent with current practices in the industry today. The SDT does not believe that the footnote violates any regulations concerning transmission planning. The proposed process simply brings stakeholders including local regulators to the table in an open and transparent manner. No change made. While the requirement is not mandatory for use in a Corrective Action Plan until Year One, the SDT believes that it would be a good practice to move forward as soon as an entity knows it is contemplating usage of the footnote. And nothing in the document precludes such action. Since the applicable regulator would be at the table and would therefore see potential uses of the footnote prior to Year One, the stakeholder process provides the opportunity to get any potential timing issues out before they become a impediment. Furthermore, the remand Order made it clear that oversight was required for instances where use of footnote 'b' was proposed. This would imply that FERC does not believe that audit and self-certification is sufficient in this matter. No change made. The ERO is not participating in the planning process. The role of the ERO is restricted to a determination of whether the planned utilization of footnote 'b' will cause an Adverse Reliability Impact to the BES. The ERO has no further role in the transmission planning process beyond that determination. No change made.		
TVA Transmission Reliability Engineering and Controls	No	TVA believes that the requirements of 25 MW as well as any Bulk contingency over 300-kV is much too burdensome. TVA believes that only larger load drops (such as 50 MW and above) should require ERO review.
Response: The SDT believes that the threshold selected is consistent with the data supplied in the data request. Increasing the		

Organization	Yes or No	Question 4 Comment
threshold to 50 MW is not consistent with the data supplied and the SDT believes that such an action would be viewed as a non-acceptable least common denominator approach. No change made.		
Iberdrola USA	No	Why would a retail service regulator approve a 300 kV and above performance issue?
Response: The voltage level is not the significant issue; the significant issue is making certain that the regulator understands that the transmission plan is to shed Load for a single Contingency so that they can understand the implications of the proposed actions and properly evaluate other available alternatives.		
LCRA Transmission Service Corporation	No	
NB Power Transmission	No	
Response: Without specific comments, the SDT is unable to respond.		
Texas Reliability Entity	Yes	1. TRE requests clarification whether the 25 MW limit of Non-consequential Load Loss (Section III (2)) applies to a single contingency event for a specific Transmission Planner's region or to the entire Planning Coordinator area. For example, if a single contingency requires multiple Transmisson Planners to shed load, is each Transmission Planner allowed to drop up to 25 MW of load before requiring regulatory review? Or did the SDT intend to require the Transmission Planners/Planning Coordinator to submit the plan for regulatory review if the total load shed for the single contingency equals or exceeds 25 MW? 2. TRE feels that the requirement in Section III that the Planning Coordinator or Transmission Planner must submit information to the ERO for a determination of whether there are "any Adverse Reliability Impacts" is overly burdensome to industry, assuming that this refers to the new definition of "Adverse Reliability Impact" (limited to Instability and Cascading). It is extremely unlikely that any such impacts will result from application of this footnote, and any that might occur will

Organization	Yes or No	Question 4 Comment
		be identified in the stakeholder process. If the ERO determination step is retained, then a timeline should be included for completion of the ERO determination process.
Response: The footnote is written on a single Contingency basis so the latter instance of the comment is correct – the plan should be submitted if the total Load shed is greater than or equal to 25 MW. Such a determination may be considered unlikely but the SDT believes that the remand Order made it clear that oversight was required for instances where use of footnote 'b' was proposed. The ERO is aware of the proposed responsibility and has accepted this role if the industry approves. Therefore, the SDT does not believe that a timeline is required. No change made.		
California Independent System Operator	Yes	Despite a public consultation process that includes the regulator(s), the standard then calls for notification to the regulator(s) and only moving forward once the regulator indicates that it does not oppose the shedding of load ("once assurance has been received that..."). This is still requiring the regulator to do something, and could be problematic if no response is provided by the regulator. How would one address silence on the part of the regulator?
Response: The SDT believes that Sections I and III represent two separate and distinct instances of the process. In Section I, the regulator is just one of perhaps many interested and applicable parties. However, in Section III, where larger values of Load are involved, there is a more formal role for regulators to play. Each local situation is unique – in some there may be formal approval provided, in others just a lack of dissent. If the regulator is silent on the proposal, the entity can move forward with the plan. No change made.		
Lincoln Electric System	Yes	While supportive of Section III, LES believes the language in the last paragraph could be further enhanced with the following changes [located in brackets] to ensure a complete and accurate record is provided to the ERO."Once [written] assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Non-Consequential Load Loss under footnote 'b', the Planning Coordinator or Transmission Planner must submit the [written assurance and] information outlined

Organization	Yes or No	Question 4 Comment
		in items II.1 through II.8 above to the ERO…”.
Response: The SDT does not believe it is appropriate to add ‘written assurance’ as the requirement only involves lack of dissent. No change made.		
Duke Energy	Yes	
SERC EC Planning Standards Subcommittee Associated Electric Cooperative	Yes	
Southern Company	Yes	
American Electric Power	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Deseret Generation & Transmission	Yes	
American Transmission Company	Yes	
Public Service Company of New Mexico	Yes	
Idaho Power Company	Yes	
SCE&G	Yes	
Georgia Transmission Corp	Yes	

Organization	Yes or No	Question 4 Comment
Response: Thank you for your support.		

5. If you have any other comments on this Standard that you haven't already mentioned above, please provide them here:

Summary Consideration: The comments supplied for question 5 are basically repetitive of what was stated for previous questions. Responses are provided consistent to what was stated above.

The following changes have been made due to industry comments:

TPL-002-1c: footnote b) - ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load.

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Independent Electricity System Operator	(1) We'd like to reiterate our support for allowing load interruption for a singlecontingency with sufficient review/oversight and under acceptable conditions, including no adverse impact on the reliability of the interconnected bulk power system. The reliability aspects (BES performance requirements) should be reviewed for acceptability by the adjacent Planning Coordinators and Transmission Planners. However, issues pertaining to economics or externalities which may not be directly reliability-related are always available for review and debate by the stakeholders via the regulatory processes and subject to approval by the regulatory authority of each jurisdiction (including those in Canada and Mexico). (2) Furthermore, we request that Table 1 of TPL-001-3 (previous TPL-001-2 approved by NERC BOT) be corrected for EHV contingencies in P2, P4 and P5 categories to allow the application of footnote 'b'/'12' that is allowed for the P1 events. Events in P2, P4, and P5 can involve more elements and can be more onerous and stressful to the system than the P1 events, and if use of footnote 'b'/'12' is permitted in the less stressful P1 events, it should also be permitted in P2, P4 and P5 events. (3) We suggest that NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve it. Accordingly, we believe that the focus of footnote 'b', and footnote 12 should be that interruption of load must not have an adverse impact on the reliability of the interconnected bulk power system. A continent-wide standard should not concern itself with the reliability of supply or supply continuity for local load, as that is the

Organization	Question 5 Comment
	responsibility of the applicable regulatory authority or its agencies responsible for local transmission and retail service over the load to be curtailed.As mentioned above, NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve it. In this regard, we believe that Attachment 1 is not necessary because it prescribes a process which goes beyond the outcome of the standard and dictates how stakeholdering must be carried out. The individual jurisdiction should establish the process for ensuring compliance with the standard and decide to what extent a stakeholdering process is necessary to establish the acceptable level of load rejection for the area in a manner consistent with local transmission established service levels.
Hydro One Networks Inc.	(1) We'd like to reiterate our support for allowing load interruption for a single contingency with sufficient review/oversight and under acceptable conditions, including no adverse impact on the reliability of the bulk electric system. The reliability aspects (BES performance requirements) should be reviewed for acceptability by the adjacent Planning Coordinators and Transmission Planners. However, issues pertaining to economics or externalities which may not be directly reliability-related are always available for review and debate by the stakeholders via the regulatory processes and subject to approval by the regulatory authority of each jurisdiction (particularly those in Canada and Mexico). (2) Furthermore, we request that Table 1 of TPL-001-2a (previous TPL-001-2 approved by the NERC BOT) be corrected for EHV contingencies in P2, P4 and P5 categories to allow the application of footnote 12 that is allowed for the P1 events. If a load is allowed to be interrupted for a single EHV transmission line contingency (Category P1), it should be allowed to interrupt the same load if the primary breaker fails (the event becomes category P4) and the fault is cleared by other breakers. Similarly, if the same breaker has an internal fault or there is a fault on the same bus section (Category P2) or there is a failure of a relay (Category P5), which results in the loss of the same EHV transmission line, it should be allowed to interrupt the same load. Events in P2, P4, and P5 can involve more elements and can be more onerouse and stressful to the system than the P1 events, and if use of footnote 12 is permitted in the less stressful P1 events, it must also be permitted in P2, P4 and P5 events. This issue has been raised by many entities in previous occasions and we believe the STD has not provided a convincing response.

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	(3) We suggest that NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve them. Accordingly, we believe that the focus of foot note 'b', and footnote 12 should be that interruption of load must not have a widespread, adverse impact on the reliability of the interconnected BES. A continent-wide reliability standard should not concern itself with the reliability of supply or supply continuity for local load, as that is the responsibility of the applicable regulatory authority or its agencies responsible for local transmission and retail service over the load to be curtailed. If NERC and/or FERC believe that MW threshold needs to be addressed within NERC Standard for US registered entities then the standard must clearly state that the requirement is for US registered entities only.
Response: (1) Thank you for your support. (2) Such discussion is out of scope for this project since TPL-001-2 has been approved by the industry through the standards development process and by the NERC Board of Trustees. Nothing in this project affects where footnote 12 is applied within Table 1. The only change being proposed is to the details of how to utilize footnote 12 as shown in the proposed Attachment 1. No change made. (3) FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand, and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. Canadian entities are allowed to adopt ERO Reliability Standards, reject them outright, or adapt them for their own use within the confines of provincial regulations. Nothing has changed in that regard with this proposed standard. No change made.	
Manitoba Hydro	(1) Effective Date section 5: The language used in the revision that was made is fine, however, where the language has been placed in the section is confusing. The language has been added to the end of the sentence that starts 'in those jurisdictions where regulatory approval is not required' and lumped those two concepts together. In our mind, there should be 3 separate concepts 1) where regulatory approval required 2) where regulatory approval not required and 3) as may otherwise be approved by applicable laws. (2) Corresponding changes do not appear to have been made, TPL 1 and TPL 2 are not consistent in terms of the language used in the Effective Date section or the Attachment 1 (the sections to

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	which changes were made since last circulation).
Response: (1) The language used in the effective date section is provided by NERC Legal and was designed to take into account the situations raised in the comment. No change made. (2) The SDT wishes to point out that the language may be slightly different due to the specific circumstances regarding definitions, etc., in the timeframe relevant to the two standards. However, the SDT believes that the language used in the two standards is consistent. Without specific references the SDT is unable to respond further. No change made.	
ACES Power Marketing Standards Collaborators	(1) The SDT needs to consider the connection between the developing standards to maintain and improve reliability with the costs required to meet those standards. We believe there is an imbalance of the costs associated with meeting compliance for the current draft standard with proposed benefit of maintaining reliability of the BPS. This standard is a good candidate for the CEAP initiative to determine the cost benefits of reliability. (2) The standard needs to allow more flexibility regarding the use of planned load shed to address transmission performance issues in the planning horizon. It needs to recognize that these planned load shedding events may only be preliminary decisions for addressing problems that are several years away. If there is little chance that the planned shed load will ever be relied upon in the operating time horizon, there should be much less stringent requirements. For instance, if a PC or TP relies on planned load shed for year five of the planning horizon but year one does not utilize the planned load shed, they have four years to develop another solution. Why should an entity expend great effort and resources for year five when another solution will likely be developed within that time period? (3) What does "materially changed" mean and what degree of a change would be considered material in the Attachment 1 stakeholder process? The SDT should clarify specific conditions in Section II that would constitute a material change. (4) Thank you for the opportunity to comment.
Response: (1) Cost factors are one of the elements in the list of criteria in Section II. Costs of different alternatives will be part of the information provided and rationales for selection or non-selection of alternatives should include consideration of costs. The CEAP	

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initiative is still a work in progress and will not be ready for use in the timeframe of this project. No change made. (2) The SDT agrees that more flexibility is needed in the longer term; therefore, in the Long-Term Transmission Planning Horizon the stakeholder process is not required, and its use is limited to the Near-Term Transmission Planning Horizon. However, the SDT believes that it is appropriate for planners to share future information in Section II so stakeholders are aware of any potential Load shed. No change made. (3) The SDT believes that the planning entity has the best understanding of when a change would become material. With the large range of design philosophies and geographic difference between the entities within NERC, it is not practical to adopt a single one size fits all approach. In addition, since the use of footnote 'b' will be a part of the entity's Corrective Action Plans, interested stakeholders will have the opportunity to question the continued use of footnote 'b'. No change made.	
Sacramento Municipal Utility District	1) The decision of necessary infrastructure addition versus a determination of load shed in lieu of costly transmission should be determined at the Public Utility Commission or Local Board of Directors not through a laod level limitation. 2) There are no impacts to the BES for load shedding actions where it is determined that it is confined to a set boundaryand demonstrate to not lead to cascading, uncrontrolled separation or blackout. 3) Where a concern that a stakeholder process be "gamed" to allow the unscrupulous entity to claim notification of affected stakeholders was followed should not dictate a continent-wide standard direction for other stakeholders.
Response: 1) FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. No change made. 2) The use of Footnote 'b' as proposed provides assurance that there is no Adverse Reliability Impact. No change made. 3) The conditions placed on the stakeholder process will provide consistency in the application of footnote 'b' on a continent-wide basis. No change made.	
Tri-State G&T	1. It is not clear how transmission projects with long lead times (such as T-lines) would be handled

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	by "Footnote b". In other words, it is not clear if it is acceptable for a TP to plan for shedding Firm Demand in the Near Term Planning Horizon without meeting the conditions shown in "Attachment 1" when a mitigating project is planned that cannot be constructed in the Near Term Planning Horizon. 2. NERC Functional Model definitions for Planning Authorities and Transmission Planners do not include the types of activities being proposed in "Attachment 1." As written, this standard mandates functions on functional entities that are outside those defined by the NERC Functional Model. 3. In the NERC Glossary of Terms, Interruptible Demand is defined as "Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment." The process described in Attachment 1 creates an agreement between stakeholders (aka "end-use customers") and their transmission providers for shedding Demand. Thus, if the process described in Attachment 1 is followed, the "Firm Demand" referenced in "Footnote b" would be reclassified as "Interruptible Demand." In essence, Firm Demand would not be interrupted. If this was the intention of FERC, NERC, and the Drafting Team, the standard should just state "Interruption of Firm Demand is not allowed." 4. It is not clear how section III of "Attachment 1" would be applied to entities that only deliver wholesale electric service and not retail electric service.

Response: 1. Any instance of proposed Load shed for a single Contingency situation in a Planning Assessment must meet the conditions of footnote 'b'. No change made.

2. The NERC Functional Model is a guideline for activities required of cited functional entities. It is periodically updated as conditions change. While the activities mentioned in the standard may not be explicitly spelled out in the NERC Functional Model, the SDT does not believe that they are out of scope for either a Planning Coordinator or a Transmission Planner. No change made.

3**.** Upon reviewing the comments, the SDT has seen that Demand that is not included as Firm Demand for footnote 'b' could be clarified as shown below.

TPL-002-1c: footnote b) - ~~It is recognized that Firm~~ <u>For purposes of this footnote, the following are not counted as Firm</u> Demand ~~will be interrupted if it is~~: (1) <u>Demand</u> directly served by the Elements removed from service as a result of the

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Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load. 4. The SDT believes that the wholesale customer will be one of the stakeholders included in the process and any use of the footnote must go through the stakeholder process. No change made.	
MRO NSRF USACE MidAmerican Energy Company	1. In TPL-002-1c Table I and TPL-001-2a Table 1 can “Firm Demand interruption” or “Non-Consequential Load Loss” be initiated by a manual event such as operator action or does it need to be automatic? RECOMMENDATION: In TPL-002-1c Table I footnote ‘b’ add a sentence stating “Acceptable methods to enact Firm Demand Interruption may include manual or automatic processes that can be initiated within a reasonable timeframe”
Minnkota Power Cooperative Otter Tail Power Company	1. MPC QUESTION: In TPL-002-1c Table I and TPL-001-2a Table 1 can “Firm Demand interruption” or “Non-Consequential Load Loss” be initiated by a manual event, such as operator action, or does it need to be automatic, such as Under Voltage Load Shedding? a. RECOMMENDATION: In TPL-002-1c Table I footnote ‘b’, add a sentence stating “Acceptable methods to enact Firm Demand Interruption may include manual or automatic processes that can be initiated within a reasonable timeframe”
Response: Whether an action is automatic or manual is of no concern with regard to footnote ‘b’ as long as manual actions are executable within the time duration applicable to the Facility Ratings. No change made.	
California Independent System Operator	A concern with the new TPL-001-2 standard is what we see as being the elimination of the existing footnote c, the footnote that qualified Category C load shedding as “may be necessary”. The wording under the new TPL-001-2 appears that load shedding is the unqualified expectation of the criteria for C contingencies.
Response: The SDT clarified the expectations for the former Category ‘C’ Contingencies when it developed proposed TPL-001-2. TPL-001-2 was approved by the industry through the standards development process and by the NERC Board of Trustees. Nothing in this project affects where footnote 12 is applied within Table 1. The only change being proposed is to the details of how to utilize footnote 12 as shown in the proposed Attachment 1. Any discussions concerning the application of the footnote within the performance table are therefore out of scope for this project. No change made.	

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Iberdrola USA	A one-paragraph footnote encompassing a 2-page attachment is cumbersome for a Reliability Standard.
Response: The SDT made every effort to make the revisions required to be as simple as possible while meeting the requirements of the remand Order. No change made.	
BC Hydro and Power Authority	BC Hydro appreciates the efforts of the SDT in revising standards TPL-002-1c - System Performance Following Loss of a Single BES Element (footnote b) and TPL-001-2a - Transmission System Planning Performance Requirements (footnote 12). BC Hydro votes YES in support of this ballot and wishes to provide the following two comments:1.At this time BC Hydro has concerns about the level of stakeholder consultation that might be required as a result of the implementation of this standard and will bring this concern to the attention of our regulator if necessary. 2.At this time BC Hydro has concerns about the instances for which regulatory review of non-consequential load loss under footnote 12 is required and will discuss those with our regulator if necessary.
Response: 1. and 2. The SDT understands your situation and comment and appreciates your overall support.	
Hydro QuÃ©bec TransÃ‰nergie	Even if the SDT said it is not in its scope, the following difficulty with the application of note 12 needs to be addressed by NERC. There are no limit on non-consequential load loss for Single Contingency P2-2. and P2-3. (HV only), multiple Contingencies P4 and P5 (HV only), and P6 and P7. The note 12 allows limited non-consequential load loss for single contingency P1, Multiple Contingency P3. Non-consequential load loss is not allowed for P2-2 and P2-3. (EHV), and P4 and P5 (EHV). Considering the EHV Facilities, it is not reasonable to accept some non-consequential load loss for single contingency P1 and P2-3, and then deny it for Multiple Contingency categories P4 and P5 which are statistically less frequent than the former. Also, the Multiple Contingency P7 (for which there is no limit on non-consequential load loss) is more frequent than P2-3, P4 and P5. This technical irregularity must be reviewed and addressed.

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Northeast Power Coordinating Council	There are no limits on non-consequential load loss for Single Contingency P2-2 and P2-3 (HV only), multiple Contingencies P4 and P5 (HV only), and P6 and P7. Footnote 12 allows limited non-consequential load loss for single contingency P1, Multiple Contingency P3. Non-consequential load loss is not allowed for P2-2 and P2-3 (EHV), and P4 and P5 (EHV). Considering the EHV Facilities, it is not reasonable to accept some non-consequential load loss for single contingency P1 and P2-3, and then deny it for Multiple Contingency categories P4 and P5 which are statistically less frequent than the former. Also, the Multiple Contingency P7 (for which there is no limit on non-consequential load loss) is more frequent than P2-3, P4 and P5. This technical irregularity must be reviewed and addressed.
Response: TPL-001-2 was approved by the industry through the standards development process and by the NERC Board of Trustees. Nothing in this project affects where footnote 12 is applied within Table 1. The only change being proposed is to the details of how to utilize footnote 12 as shown in the proposed Attachment 1. No change made.	
Southern California Edison Company	Footnote "b"/Footnote 12 as currently written does not provide for an exemption to allow for the use of Firm Demand interruption as a short-term solution to transmission problems. Many entities would benefit from being allowed to use Footnote "b"/Footnote 12 as a temporary solution in response to construction delays until facilities to mitigate an N-1 contingency identified in a Planning Assessment can be installed. Under the current proposal, the stakeholder process will provide very little value in attempting to resolve such a problem. In fact, the current Footnote "b"/Footnote 12 could result in a stakeholder process that may actually slow the implementation of mitigation measures for the system.
Response: The SDT does not agree that the footnote does not provide for the use of Firm Demand interruption as a short-term solution to transmission problems. That has always been the point of the footnote and nothing in this project has changed that intent. The only changes are to the method in which the footnote is invoked. No change made.	
ISO New England	In summary, the main footnote is unobjectionable, but this standard as proposed has misplaced jurisdictional authority under Section 215 of the Federal Power Act for both states and the ERO through several of the process points and conditions set out in the attachment to the stardard. The removal of references is required for the standard to comport with the law. These revisions to

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	the standard can be made, which would then allow the draft standard to comply with FERC's further guidance and the other legal limitations described above.
Response: The SDT believes that the role provided to regulatory bodies is consistent with current practices in the industry today. The SDT does not believe that the footnote violates any regulations concerning transmission planning. The proposed process simply brings stakeholders including local regulators to the table in an open and transparent manner while setting criteria for when footnote 'b' can potentially be utilized. The ERO is not participating in the planning process. The role of the ERO is restricted to a determination of whether the planned utilization of footnote 'b' will cause an Adverse Reliability Impact to the BES. The ERO has no further role in the transmission planning process beyond that determination. No change made.	
Ameren	It might be helpful to probe further with the respondents who have no planned upgrades identified to address the dropping of non-consequential load to see what relevant system upgrades might entail, and the estimated costs associated with such upgrades, to address such situations.
Response: The SDT used the Section 1600 data request process to the best of its ability within the limited timeframe afforded to this project. No change made.	
LCRA Transmission Service Corporation	LCRA TSC disagrees with the October 2012 revision of TPL Table 1 Steady State & Stability Performance Footnotes (TPL-002-1c, footnote 'b' and TPL-001-2a footnote 12). The proposed stakeholder process required to be conducted during each Planning Assessment is overly burdensome. Further, it is not clear from the proposed process that a key concern expressed by the Commission with respect to use of Firm Demand load shedding is addressed - Notice to Firm Demand Customers. In addition, the proposed stakeholder process introduces several questions that need to be further clarified. For example: 1) Who defines the processes and procedures to be used? 2) Who is/are the decision maker(s)? 3) Who determines if the processes and procedures were followed?

Organization	Question 5 Comment
	4) Who carries out the administrative tasks (such as notice, securing meeting space,....)? 5) Who can participate? Does someone need to demonstrate a material interest in order to participate? 6) What are the means of participation (accepted forms of communication, timelines...)? 7) What are the criteria for decision-making? 8) What is the process for dispute resolution? How would does an Attachment become part of a NERC Standard? Should Attachment 1 be a requirement? In addition, support is needed for the bright-line 25 MW level. Lastly, the statement, "Before a Firm Demand interruption under footnote 'b' is allowed to be utilized as an element of a Corrective Action Plan in Year One of the Planning Assessment," implies that Firm Demand interruption may be used for years two through five of the Planning Assessment without the stakeholder process.

Response: Stakeholders representing the interests of Firm Demand customers would certainly be among the parties involved in Section I of the stakeholder process. No change made.

1) through 8) There is not a one-size-fits-all response to these questions for a continent-wide standard. The SDT provided the key components of an open and transparent stakeholder process while allowing variations that may be required due to differing structures and frameworks across the continent. Therefore, the answers to these questions may be different for each individual stakeholder process.

Attachments have been used in the past in other standards and are an accepted part of a standard.

The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. The 25 MW threshold was directly derived from this data. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made.

Organization	Question 5 Comment
The SDT disagrees with the statement made by the commenter. Firm Demand interruption must go through the process for any year in the Near-Term Transmission Planning Horizon as is clearly stated in the main body of the footnote. No change made.	
TVA Transmission Reliability Engineering and Controls	Please see responses to question #2,3, and 4. TVA believes that only load drops of higher magnitudes go thru the Stakeholder and regulatory review.
Response: Please see responses to questions 2, 3, and 4.	
Public Utility District No.1 of Snohomish County MEAG Power City of Austin Clark Public Utilities	Public Utility District No.1 of Snohomish County generally disagrees with the October 2012 revision of TPL Table 1 Steady State & Stability Performance Footnotes (Planning Events and Extreme Events). "Footnote b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW.""Footnote 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed '75' MW."

Organization	Question 5 Comment
	The proposed revisions require that a Transmission Planner or Planning Coordinator provide assurance that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the interruptions of firm demand under TPL-002 footnote 'b' or TPL-001 footnote '12' if the voltage level of the contingency is greater than 300 kV with certain sub-conditions or if the planned interruption of firm demand under these footnotes is greater than 25 MVA. In addition, under no case can planned Non-Consequential Load Loss exceed 75 MW.The magnitude and duration of load loss is a Level of Service ("LOS") or Customer Service issue that is the jurisdiction of Public Utility Commissions and Local Electric Utility and Municipality boards. The boards and commissions represent their customers which often have diverse service and rate expectations that often are a result of local industry requirements, geography, urban/rural characteristics, and other factors of the particular service territory. Boards and commissions hold public meetings seeking input on various utility matters that often address services and rates. The rate impacts for customers are important; often more important than the service levels depending on the particular customer or customer class. Local boards and commissions are very close to these issues and weigh the input provided through public testimony to best represent their customer needs over the region they represent and have jurisdiction under state and local codes to address.The 75 MW Non-Consequential Load Loss threshold and the required NERC process do not resolve or address a reliability issue. The TPL footnotes address service requirements and should not be part of a NERC Reliability Standard any more than mandating specific System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI"). The Non-Consequential Load Loss requirement is an economic driven threshold that is not consistent throughout North America due to diverse customer needs and expectations. For instance, in some areas it may make economic sense and receive local approval to fund a $100 million system reinforcement to mitigate 1 in 20 year (5 percent chance of occurring) 76 MW Non-Consequential Load Loss exposure. However there are many communities that could not justify or support multi-million facilities to mitigate a 1 in 20 year event that may cause the Non-Consequential Load Loss of 76 MW of load. Public Utility District No.1 of Snohomish County supports removing the Non-Consequential Load Loss thresholds from the TPL Reliability Standards and allow the local boards and commissions to continue to address Customer Service Level issues as they are closest to the customers' needs and have jurisdiction over this issue.

Organization	Question 5 Comment
Response: The SDT used the Board of Trustees approved standard as a starting point for this draft. FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. The proposed standards include the local regulatory bodies at every step in the process. This will allow those bodies to have input at every step. The SDT believes that the proposed changes to the standards are in alignment with the charge that was given to it. No change made.	
Xcel Energy	Setting limits on the amount of NCLL only sets the stage for failure in the compliance of NERC standards and fails to take note of what is really the issue; the planning of a transmission system that is both reliable and economically viable for all stakeholders and customers. It should be emphasized that the use NCLL in a "planning process" is only assuming the conditions set in the study will exist and in no way reflects the conditions seen during the day to day operation of the transmission system. Xcel Energy is concerned about the previous ability on loss of load in anticipation of the next outage (previously C3 now P6). For TPL-003, loss of load in anticipation of the next system outage was covered under footnote B. Footnote 9 now states, "...the re-dispatch does not result in any Non-Consequential Load Loss. " This is a large increase in requirements of the transmission system to operate. As written, it appears that footnote 12 is NOT applicable to P6 contingencies. Please clarify is this is the intent.
Response: The SDT does not believe that it needs to add language emphasizing that there is a difference between planning and operations when these standards are clearly planning standards. No change made. The SDT disagrees that there was a previous ability to shed Load in anticipation of the next Contingency. Footnote 'b' only allowed curtailment of firm transfers in preparation for the next Contingency. In addition, footnote 12 is not applicable for P6 planning events since Non-Consequential Load loss is allowed. No change made.	
Arizona Public Service Company	The following comment relates to Table 1. It is not clear why footnote 12 applies only to P2-1. The events P2-2, P2-3, P4, P5 are much less probable and the footnote 12 should be applicable to all these events. Why is that loss of non-consequential load is allowed for line tripping without fault but not for a bus fault which is much less likely and could result into same line trip. Similar

Organization	Question 5 Comment
	arguments apply to other scenarios listed above.
Response: TPL-001-2 was approved by the industry through the standards development process and by the NERC Board of Trustees. Nothing in this project affects where footnote 12 is applied within Table 1. The only change being proposed is to the details of how to utilize footnote 12 as shown in the proposed Attachment 1. Any discussions concerning the application of the footnote within the performance table are therefore out of scope for this project. No change made.	
Electric Reliability Council of Texas, Inc.	The SDT is not required to utilize the stakeholder approach by Order 762 or any other relevant FERC orders. FERC merely provided guidance as to how the rejected proposal could be improved. However, if the SDT elects to pursue an exception process, such exceptions should be based on objective criteria, and the process should be external to the NERC Reliability Standards (e.g. in the Rules of Procedure).In Order 693, FERC directed NERC to clarify footnote (b) to prohibit shedding firm load except for consequential load loss (Order 693 at PP 1773, 1794 and 1797}. In a related compliance order, FERC reaffirmed its position. (130 FERC 61,200 (March 18, 2010) at PP 8-10 (Compliance Order)) In a subsequent order, FERC clarified that its Order 693 directive did not preclude consideration of specific comments related to planning the system based on load shedding at the “fringes" of a system. (131 FERC 61,231 (June 11, 2010) at P 21 (Clarification Order)) FERC held that regional variances for case-specific circumstances or a case-specific exception process to plan for the loss of firm service “at the fringes of various systems" would be acceptable. (131 FERC 61,231 (June 11, 2010) at P 21 (Clarification Order)) However, FERC also stated that it viewed the basis for such exceptions as economic, not reliability, with the justification being that it was not economic to invest in the bulk electric system to serve all non-consequential load customers under some single contingency conditions. (Order 693 at P 1792) FERC made clear that any such regional differences or case specific exception processes cannot reflect the lowest common denominator, and, they must be technically justified, and such justification must be strong. (Clarification Order at P 21, See also Order 693 at P 1794) This is consistent with FERC's position that this is a matter of "fundamental issue of transmission service". (Order 693 at P 1793) In recognizing that meeting firm demand under single contingency conditions is fundamental to transmission service, FERC noted that NERC's definition of firm transmission service is the "highest quality (priority) service offered to customers ... that anticipates no planned interruption." (Order 693 at P 1793)Against this background, NERC filed

Organization	Question 5 Comment
	revisions to footnote b that allowed transmission plans to shed non-consequential load under single contingency conditions, provided appropriate process applied to such planning determinations/outcomes. In Order No. 762, {139 FERC 11 61,060 (April 19, 2012)) FERC rejected the approach proposed by NERC and provided guidance on acceptable approaches to footnote b. However, FERC did not endorse or mandate any particular approach. Rather, it merely urged "NERC to develop in a timely manner an appropriate modification that is responsive to the Commission's directives in Order No. 693 and our concerns set forth in this Final Rule." (Order 762 at P21) FERC stated that in order for any such proposal to have merit, it must be technically justified and must not reflect the lowest common denominator.As discussed, the proposed stakeholder approach is not appropriate for NERC Reliability Standards. The SDT should abandon that approach and consider simple revisions to footnote b that reference a case by case exception process based on objective criteria that is external to the NERC Reliability Standards (e.g. Rules of Procedure). Alternatively, it should develop revisions to the continent-wide standards that clarify that non-consequential load shedding is not generally permitted for single contingency conditions, but, consistent with FERC's orders, exceptions could be established pursuant to regional rules based on the need/appropriateness in a particular region.Consistent with the above discussion, if the SDT elects to pursue revisions that accommodate shedding non-consequential load in transmission planning for single contingency conditions, it should abandon the stakeholder process approach. The establishment of exceptions is better suited for regional rules or pursuant to a process outside of the reliability standards - e.g. via the Rules of Procedure, because such a process is not suited for a continent-wide reliability standard. Regardless of whether the issue is addressed via an external process, or left to regional variances, this issue needs to be addressed in a relatively timely manner because the uncertainty is affecting planning processes.

Response: FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. The SDT has set up criteria for consideration in the potential usage of footnote ‘b’ for planning purposes in Attachment 1, Section II, Bullets 1 through 8. The criteria described are objective. The process described does not tell a entity how to go about its business but only describes what must be done to allow for the usage of footnote ‘b’ in the planning process. The SDT believes that the referenced exception process is what is being proposed. The proposed process sets up an open and transparent process for allowing such Load shed in

Organization	Question 5 Comment
specific conditions and with specific limitations. Any future revisions to footnote 12 will be accomplished through the approved standards development process and any discussion on changing threshold values would be part of that process. No change made.	
Midwest Independent Transmission System Operator, Inc.	We do not support using a stakeholder process to determine if Non-conseqeuntial Load Loss is appropriate following a single contingency event as a means to satisfy the standard. Stakeholder processes will nearly always result in disagreements. The parties that may be responsible for payment of upgrade costs will not necessarily line up with the parties adversely impacted by the alternative load loss. If the stakeholder process includes all stakeholders, there may be many more stakeholders impacted by upgrade costs based on broader benefits and/or cost sharing than stakeholders impacted by the alternative load loss. This will result in the majority decision of a stakeholder body to most often be one that supports load shed (until it is their turn to be the load that is shed). On the other hand, if the stakeholder process is limited to only the stakeholders directly impacted by the proposed load shed, to the extent those stakeholders pay only a small part of the upgrade costs, they will always select a potentially costly upgrade to avoid load shed. The point is, we do not believe that it possible to have a fair and impartial stakeholder process to correctly determine if and when load shed is acceptable to assist in satisfying a single contingency standard. Since the general intents of the existing TPL-002-1 standard and proposed TPL-001-2 standard are not to rely on any shedding of non-consequenital load to meet a single contingency event, in the event that footnote b of TPL 002-1 or footnote 12 of TPL 001-2 is not eliminated, we believe that it should be narrowly focused only on those situations for which the original footnote was developed: interruption of service to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, where the overall reliability of the interconnected transmission system is not impacted. We propose that footnote b and footnote 12 be modified as follows to ensure it is not misapplied:”An objective of the planning process is to avoid Non-Consequential Load Loss following Contingency events. In limited circumstances, Non-Consequential Load Loss may be needed within the planning horizon to ensure that BES performance requirements are satisfied. However, Non-consequential Load Loss cannot be used to avoid cascading outages or to maintain system stability. Non-consequential Load Loss also cannot be used to avoid a thermal loading or voltage limit violation on an EHV facility. When Non-Consequential Load Loss is utilized within the planning horizon to address BES performance requirements, such interruption cannot exceed 75 MW and is limited to the

Organization	Question 5 Comment
	following circumstances: o Non-consequential Load Loss is allowed for load served by a radial transmission line to avoid voltage limit violations on the radial transmission line following a single contingency event anywhere on the system.. o Non-consequential load shed is allowed for load within a local area served by not more than two transmission lines and/or transformers to avoid a thermal loading issue or voltage issue in the local area, including the transmission lines and/or transformers supplying the area, for a loss of one of the transmission lines or transformers supplying the area, so long as there are no thermal loading or voltage violations outside the local area."We believe the language above maintains acceptable reliability on the bulk electric system by limiting load shed and violations that require load shed to radial areas or areas that would be served radially following the single contingency. We therefore highly recommend that Attachment I be eliminated entirely and that the footnotes either be eliminated or replaced with the modified version above.
Response: FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. No change made.	
SCE&G	While the current revisions improve the processes described, we have concerns regarding the revisions to TPL002-1 b. SCE&G has significant concern with the proposed revision to TPL Table 1, Footnote B. The current Footnote B states "Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems". The phrase "without impacting the overall reliability of the interconnected transmission systems" is important to the TPL standards to ensure that ERO standards do not dictate the level of service to specific customers. Service to specific customers and load pockets is jurisdictional to State Commissions. ERO standards should not compromise this jurisdiction. SCE&G believes that any proposed revisions to Footnote B must maintain the concept that planned or controlled interruption of electric supply to customers, whether they are radial or network, is allowed as long as it does not impact the overall reliability of the interconnected transmission systems. The proposed revision eliminates this concept

Organization	Question 5 Comment
Response: The SDT believes that the suggested wording is redundant as the quoted statement is the basis for standards activities. No change made.	

END OF REPORT

Consideration of Comments

Project 2010-11 Revision of TPL-002 footnote ‘b’

The Project 2010-11 TPL Table 1 Order Drafting Team thanks all commenters who submitted comments on the proposed standards, TPL-002. The standard was posted for a 30-day public comment period from December 12, 2012 through January 11, 2013. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 49 sets of comments, including comments from approximately 132 different people from approximately 48 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Summary Consideration:

The SDT made one change to the proposed standards to address industry comments. This change was made in the main body of the footnote to address a specific jurisdictional concern for non-US entities.

> **TPL-001-2a and TPL-002-1c (main body of the footnote) -** In no case can the planned Firm Demand interruption under footnote ‘b’ exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

In order to avoid confusion, a duplicative statement on the applicability of the 75 MW constraint was deleted from Section III.

The SDT also corrected the grammar in Section III, changing ‘does’ to ‘do’ in the applicable sentences, as follows:

> **Section III –** “… the applicable regulatory authorities or governing bodies responsible for retail electric service issues do~~es~~ not object …”

In addition, in the course of researching industry comments, a typo was discovered and corrected as follows:

> **TPL-002-1c: footnote ‘b’ –** “…For purposes of this footnote, the following are not counted as Firm Demand~~t~~: (1) …”

No other changes were made.

While the revision for non-US registered entities qualifies as a significant change to the standards, the Standards Committee has decided that since the indicated change was simply for a jurisdictional issue, and did not change the technical content or intent of the standard, that this project can be moved forward to the recirculation ballot stage.

Unresolved minority issues:

Some respondents continue to raise jurisdictional concerns with the proposed standards. The general line of thought in those comments is that NERC is imposing itself into the local planning process in violation of existing statutes. The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. In Order 693, FERC clearly stated that it has jurisdiction over matters that involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote 'b' solution acknowledges these facts and the SDT believes it is an appropriate response to FERC directives on this matter.

Many commenters questioned the use of a stakeholder process at all. Those commenters expressed the opinion that the FERC Order did not mandate the use of the stakeholder process. The SDT used the Board of Trustees approved standard as a starting point for this draft. FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach, in order to address these concerns.

A few commenters indicated disagreement with the 75 MW limit the proposed standards place on the amount of Non-Consequential Load that can be planned to be shed for a single contingency, with some commenters indicating that the limit should be higher than the proposed limit while others indicated that planning to shed load was inconsistent with planning for a reliable bulk power system.

Finally, some commenters continue to question facets of the proposed TPL-001-2a standard previously approved by the industry and the NERC Board of Trustees. These commenters are questioning the application (or non-application) of footnote 12 for various planning events. . The SAR for this project took the approved TPL-001-2 as the starting point for the specific discussion of footnote 'b'/12 and does not allow for review of previously approved applications of the footnote, which were developed and reached ballot pool consensus and Board approval in a previous effort.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Jim Kelley	SERC EC Planning Standards Subcommittee	X				X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Company	SERC	1
2.	Charles Long	Entergy	SERC	1
3.	Edin Habibovic	Entergy	SERC	1
4.	James Manning	NC Electric Membership Corporation	SERC	1
5.	Philip Kleckley	SC Electric & Gas	SERC	1
6.	Shih-Min Hsu	Southern Company Service	SERC	1
7.	Darrin Church	TVA	SERC	1
8.	Bob Jones	Southern Company Service	SERC	1
9.	Pat Huntley	SERC Reliability Corporation	SERC	10

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Wayne Sipperly	New York Power Authority	NPCC	5
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Donald Weaver	New Brunswick System Operator	NPCC	2
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Christina Loncz	PSEG Power LLC	NPCC	5
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Group	X	X	X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	Robert Rhodes	Southwest Power Pool	SPP	NA
3.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
4.	Don Taylor	Westar Energy	SPP	1, 3, 5, 6
5.	Stephen McGie	City of Coffeyville	SPP	NA
6.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
5. Group	Terry L. Blackwell	Santee Cooper	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Vicky Budreau	Santee Cooper	SERC	1
2.	Jim Peterson	Santee Cooper	SERC	1
3.	Chris Jimenez	Santee Cooper	SERC	1
4.	Chris Wagner	Santee Cooper		1
5.	Cindy Corson	Santee Cooper		1
6.	Mike Coker	Santee Cooper	SERC	1
7.	Rene' Free	Santee Cooper	SERC	1
8.	Tom Abrams	Santee Cooper	SERC	1
9.	Rick Thornton	Santee Cooper	SERC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	paul haase	seattle city light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	pawel krupa	seattle city light	WECC	1
2.	dana wheelock	seattle city light	WECC	3
3.	hao li	seattle city light	WECC	4
4.	mike haynes	seattle city light	WECC	5
5.	dennis sismaet	seattle city light	WECC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	Ben Engelby	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Shaver	Arizona Electric Power Cooperative Inc./Southwest Transmission Cooperative Inc.	WECC	1, 4, 5
2.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
3.	Amber Anderson	East Kentucky Power Cooperative	SERC	1, 3, 5
4.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
5.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
6.	Scott Brame	North Carolina Electric Membership Corporation	RFC	1, 3, 4, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8. Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10

2.	TOM BREENE	WPS	MRO	3, 4, 5, 6
3.	JODI JENSON	WAPA	MRO	1, 6
4.	KEN GOLDSMITH	ALTW	MRO	4
5.	DAVE RUDPOLPH	BEPC	MRO	1, 3, 5, 6
6.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
7.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
8.	SCOTT NICKELS	RPU	MRO	4
9.	TERRY HARBOUR	MEC	MRO	1, 3, 5, 6
10.	MARIE KNOX	MISO	MRO	2
11.	LEE KITTELSON	OTP	MRO	1, 3, 5
12.	SCOTT BOS	MPW	MRO	1, 3, 5, 6
13.	TONY EDDLEMAN	NPPD	MRO	1, 3, 5
14.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
15.	DAN INMAN	MPC	MRO	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9. Group	Greg Rowland	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3
3.	Dale Goodwine	Duke Energy	SERC	5
4.	Greg Cecil	Duke Energy	RFC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10. Group	Sasa Maljukan	Hydro One Networks Inc.	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Kiguel	Hydro One Networks Inc.	NPCC	1
2.	Hamid Hamadanizadeh	Hydro One Networks Inc.	NPCC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11. Group	John Allen	Iberdrola USA	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joseph Turano	Central Maine Power	NPCC	1
2.	Raymond Kinney	New York State Electric & Gas	NPCC	1
3.	David Conroy	Central Maine Power	NPCC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12. Group	Michael Jones	National Grid	X		X							

	Additional Member	Additional Organization	Region	Segment Selection

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Michael Schiavone	Niagara Mohawk (A National Grid Company)	NPCC 3										
13.	Individual	Chris Pink	Tri-State G&T	X		X		X					
14.	Individual	Tim Ponseti, VP	TVA Transmission Reliability Engineering and Controls	X								X	
15.	Individual	Diane Barney	NARUC									X	
16.	Individual	Lloyd A. Linke	Western Area Power Administration - Transmission Owner	X									
17.	Individual	Shih-Min Hsu	Southern Company	X		X		X	X				
18.	Individual	Frederick R Plett	Massachusetts Attorney General								X		
19.	Individual	Thad Ness	American Electric Power	X		X		X	X				
20.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X									
21.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
22.	Individual	David Jendras	Ameren	X		X		X	X				
23.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
24.	Individual	David Wang	SDG&E	X									
25.	Individual	Bob Easton	WAPA-RMR	X								X	
26.	Individual	Kenn Backholm	Public Utility District No.1 of Snohomish County	X		X	X	X	X			X	
27.	Individual	Steve Alexxanderson P.E.	Central Lincoln			X	X					X	
28.	Individual	Milorad Papic	Idaho Power Company	X									
29.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						
30.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
31.	Individual	Jim Cyrulewski	JDRJC Associates LLC								X		
32.	Individual	Kathleen Goodman	ISO New England Inc		X								
33.	Individual	John Collins	Platte River Power Authority	X									
34.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
35.	Individual	Donald Weaver	New Brunswick System Operator		X								
36.	Individual	Michiko Sell	Public Utility District No. 2 of Grant County, WA	X		X	X	X	X				
37.	Individual	Michael Moltane	ITC	X									
38.	Individual	Mark Westendorf	MISO		X								
39.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
40.	Individual	Patricia Robertson	BC Hydro	X	X	X		X					
41.	Individual	Teresa Czyz	Georgia Transmission Corp.	X									
42.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
43.	Individual	Clay Young	SCE&G	X		X		X	X				
44.	Individual	Michael Falvo	Independent Electricity System Operator		X								
45.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
46.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
47.	Individual	Vijayraghavan bangalore	Pacific gas and Electric Comapny	X									
48.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
49.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The SDT thanks you for following the instructions and lessening the SDT workload. Your support for comments submitted by another entity will be noted accordingly.

Organization	Supporting Comments of "Entity Name"
Flathead Electric Cooperative, Inc.	We support the comments submitted by Central Lincoln
JDRJC Associates LLC	Midwest ISO
Kansas City Power & Light	SPP
Brazos Electric Power Cooperative, Inc.	ACES Power Marketing
ITC	MISO

1. Do you agree with changes made to the body of the footnote? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comment

Summary Consideration: In general, the SDT has responded to the individual comments and there are no technical changes proposed to the standards as a result of comments. However, the SDT has responded to a request from Canadian entities to make a change to the main body of the footnotes to address specific jurisdictional concerns for non-US registered entities.

> **TPL-001-2a and TPL-002-1c** (main body of the footnote) **-** In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

While the revision for non-US registered entities qualifies as a significant change to the standards, the Standards Committee has decided that since the indicated change was simply for a jurisdictional issue, and did not change the technical content or intent of the standard, that this project can be moved forward to the recirculation ballot stage.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	Dropping load generally should not be endorsed, but it is recognized that there are special situations where it cannot be avoided. If a regulator responsible for load is comfortable with greater than 75MW being dropped in a rare situation, there should not be a requirement to build out of the situation. Provided there is no widespread, adverse effect on the reliability of the interconnected BES, the effect of a interruption on customers is under the purview of the applicable regulatory authority that is responsible for local transmission and retail service over the load to be curtailed. NERC must acknowledge that jurisdictional authorities can decide on the parameters for planning events that do not have an impact on the reliability of interconnected BES . There are no limits on non-consequential load loss for Single Contingency

Organization	Yes or No	Question 1 Comment
		P2-2 and P2-3 (HV only), multiple Contingencies P4 and P5 (HV only), and P6 and P7. Footnote 12 allows limited non-consequential load loss for single contingency P1, Multiple Contingency P3. Non-consequential load loss is not allowed for P2-2 and P2-3 (EHV), and P4 and P5 (EHV). Considering the extensive EHV Facilities in the Canadian regions of NPCC, it is not reasonable to accept some non-consequential load loss for single contingency P1 and P2-3, and then deny it for Multiple Contingency categories P4 and P5 which are statistically less frequent than the former. Also, the Multiple Contingency P7 (for which there is no limit on non-consequential load loss) is more frequent than P2-3, P4 and P5. This technical irregularity must be reviewed and addressed. This comment was submitted for the last posting.
Response: The SDT has previously pointed out that building is not the sole source of remedy for the situation. Examples of other allowable actions were specifically provided in the January 8, 2013 webinar (http://www.nerc.com/docs/Standards/dt/footnoteb_webinar_20130108_final.pdf). No change made. The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. And when such decisions do not involve any aspect of BES operation or reliability, such situations would not come under the purview of footnote ‘b’ as standards only apply to the BES unless stated otherwise. However, in Order 693, FERC clearly stated that it has jurisdiction over matters that involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote ‘b’ solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. No change made. Table 1 in the proposed TPL-001-2 was previously approved by industry through the standards development process. As shown by this approval, the SDT and the industry disagree that there is a technical irregularity in Table 1. The Board of Trustees has also previously approved this proposed standard. Discussions on the applicability of footnote 12 in that standard were held during Project 2006-02 and are not part of this proceeding. No change made.		
Public Utility District No. 2 of Grant County, WA	No	GCPD abstains from voting on the revisions to footnote "b" in TPL-002-1c and the corresponding footnote 12 of TPL-001-2. GCPD is concerned that the revised language oversteps the bounds of the "reliability standard"

Organization	Yes or No	Question 1 Comment
		definition under Section 215 of the Federal Power Act and into customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions. However, in the spirit of moving this process forward, GCPD did not vote against the revised footnotes.
Santee Cooper	No	Santee Cooper will abstain from voting on the revisions to footnote "b" in TPL-002-1c and the corresponding footnote 12 of TPL-001-2. Santee Cooper is concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal power Act and into customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions. However, in the spirit of moving this process forward, Santee Cooper will not vote against the revised footnotes.
Response: The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. And when such decisions do not involve any aspect of BES operation or reliability, such situations would not come under the purview of footnote 'b' as standards only apply to the BES unless stated otherwise. However, in Order 693, FERC clearly stated that it has jurisdiction over matters that involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote 'b' solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. No change made.		
Hydro One Networks Inc.	No	In this comment period Hydro One would like to reiterate its initial comments. Hydro One disagrees with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard. Provided there is no widespread, adverse effect on the reliability of the interconnected bulk electric system, the effect on customers of a firm demand interruption is the responsibility of the applicable regulatory authority or its delegated agencies responsible for local transmission and retail

Organization	Yes or No	Question 1 Comment
		service over the load to be curtailed. If it is decided to proceed with the 75 MW or any other value, we propose replacing the sentence, in the footnote and in attachment one, section III that reads:"In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW." with "In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss under footnote 12 for a non-US Registered Entity should be determined by the applicable Regulatory Authority or Governmental Authority or its delegated agency in that is responsible for retail electric service issues in that jurisdiction."
Response: The SDT has made a change to the main body of the footnotes to address the concerns of non-US registered entities. **TPL-001-2a and TPL-002-1c** (main body of the footnote) **-** In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.		
NARUC	No	As stated before, if there is no reliability threat to the bulk system there is no need for the 75 MW limit on the anticipated amount of load to be shed. As long as the regulator responsible for the retail load subject to being shed is notified of the situation, the situation can be appropriately addressed at the local level.
Response: The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. In Order 693, FERC clearly stated that it has jurisdiction over matters that do involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote 'b' solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. No change made.		

Organization	Yes or No	Question 1 Comment
SCE&G	No	Comments previously submitted.
Response: Thank you for following the guidelines. Please see previous responses to this comment posted for the comment period ending November 19, 2012.		
Independent Electricity System Operator	No	Please note that the Independent Electricity System Operator (IESO), an RTO/ISO registered under Industry Segment 2, has filed an appeal with respect to NERC’s response to our similar comments submitted to the previous ballot on this project. We disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard. Provided there is no widespread adverse effect on the reliability of the interconnected bulk power system, the effect on customers of a firm demand interruption is the responsibility of the applicable regulatory authority or its agencies responsible for local transmission and retail service over the load to be curtailed. To recognize NERC’s role as the ERO for Ontario and the Memorandum of Understanding between NERC and the Ontario Energy Board, the IESO proposed replacing the sentence, in the footnote and in attachment one, section III that reads:”In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW.” with “In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss under footnote 12 for a Registered Entity that is a Canadian Entity (or a Mexican Entity) should be implemented in a manner that is consistent with/or under the direction of the Applicable Governmental Authority or its agency in Canada (or Mexico).Under this language, both the amount of non-consequential load loss, and the process under which that amount was arrived at, including stakeholder consultations, would be determined by the relevant Canadian jurisdiction, in this case Ontario.

Organization	Yes or No	Question 1 Comment
		This change will make the standard acceptable in Ontario's legislative framework, in which NERC standards come into force automatically unless, by order of the Ontario Energy Board, a standard is stayed and remanded back to NERC for further consideration. The responses to the IESO's comments in the previous ballot were inaccurate as to this key feature of the Ontario reliability framework, as addressed in the IESO appeal. An alternate solution to this issue, which would o be consistent with the intent of the responses to the IESO comments on the previous ballot, o respect the Ontario reliability framework, and o resolve the IESO January 9, 2013 appeal; and is appropriate given that these changes are being driven by a U.S. FERC remand order to NERC, would be to make the following highlighted clarifications to footnotes 'b' and 12:With respect to Standard TPL-002-1c - footnote 'b' b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm For purposes of this footnote, the following are not counted as Firm Demand will be interrupted if itt is: (1) Demand directly served by the Elements removed from service as a result of the Contingency, or and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, for U.S. registered entities when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to

Organization	Yes or No	Question 1 Comment
		circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for U.S. registered entities. With respect to Standard TPL-001-2a - footnote 12:12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, for U.S. registered entities when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for U.S. registered entities.
Response: The SDT has made a change to the main body of the footnotes to address the concerns of non-US registered entities. **TPL-001-2a and TPL-002-1c** (main body of the footnote) **-** In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.		
Iberdrola USA	No	See comment to question 4 below.
Electric Reliability Council of Texas, Inc.	No	See response to question 4.
Response: See response to Q4.		
Tri-State G&T	No	1. In the last submittal for comments, the following comment was made: It was not clear how transmission projects with long lead times (such as T-lines) would be handled by "Footnote b." In other words, it is not clear

Organization	Yes or No	Question 1 Comment
		if it is acceptable for a TP to plan for shedding Firm Demand in the Near Term Planning Horizon without meeting the conditions shown in "Attachment 1" when a mitigating project is planned that cannot be constructed in the Near Term Planning Horizon. The Standard Drafting Team (SDT) provided the following response: Any instance of proposed load shed for a single Contingency situation in a Planning Assessment must meet the conditions of footnote 'b.' No Change made. From the above comments, we believe there is a situation where the Bulk Electric System (BES) reliability is compromised while stakeholder process proceeds.
Response: This standard ensures these items are addressed in planning prior to them becoming an issue in operations so the SDT believes that BES reliability is not being compromised. No change made.		
Western Area Power Administration - Transmission Owner	No	While Western generally agrees with the proposed modification to footnote b, Western does not support the 75 MW threshold and Attachment 1 Stakeholer process. The 75 MW threshold seems to low and if a threshold it needed the drafting team should consider using a 300 MW threshold similar to that used in CIP-002, EOP-004, DOE OE-417 reporting, and NERC event analysis process. The stakeholder process seems to be duplicative, considering there FERC Order 890 planning process.
WAPA-RMR	No	While Western agrees in general with what is proposed in Footnote b; I do not agree with stipluating 2 requirements in the proposed Footnote b: The 75 MW load threshold; the Attachment 1 Stakeholder process. The 75 MW seems low and NERC should condsider using a 300 MW threshold similar to that used in CIP-002 and EOP-004 requirements.
Response: The SDT established the limit based on the results of the Section 1600 data request which clearly pointed to 75 MW as a reasonable limit. While the SDT considered a higher limit value, the data collected does not justify such an action. The SDT used the		

Organization	Yes or No	Question 1 Comment
Board of Trustees approved standard as a starting point for this draft. FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. The use of footnotes and attachments is an acceptable mechanism for use in Reliability Standards and both mechanisms have been used before. No change made. The phrase in Section I: "The responsible entity can utilize an existing process or develop a new process" was designed to allow an entity to use an existing process as long as it meets the requirements shown in Attachment 1. No change made.		
Massachusetts Attorney General	No	The SDT ignored a lot of feedback concerning the inappropriateness of a 75 MW threshold. IT remains inappropriate and an appropriate level should be decided by local stakeholder processes.
Response: The SDT established the limit based on the results of the Section 1600 data request which clearly pointed to a 75 MW limit. While the SDT considered a higher limit value, the data collected does not justify such an action. The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. In Order 693, FERC clearly stated that it has jurisdiction over matters that involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote 'b' solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. No change made.		
Entergy Services, Inc. (Transmission)	No	Attachment 1 is overly burdensome and concerns local reliability issues better left to local regulators. A planned or unplanned loss of 25 MW is inconsequential to the reliability of the BES. The footnote could be simplified to exclude attachment 1 as follows: An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES

Organization	Yes or No	Question 1 Comment
		performance requirements, such interruption is limited to 25 MW and notice must be given to applicable regulatory authorities or governing bodies responsible for retail electric service issues within 30 days of the completion of the assessment which includes the use of footnote 12.
Response: The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. In Order 693, FERC clearly stated that it has jurisdiction over matters that involve BES operations and reliability and the proposed footnote 'b' solution acknowledges that fact and is an appropriate response to subsequent FERC directives on this matter. No change made. The SDT disagrees that Attachment 1 is overly burdensome as it simply addresses items that would be part of a Transmission Planner's normal workload. No change made. As approved by the Board of Trustees, all utilizations of footnote 'b' required the use of the stakeholder process. The current proposal does not, and should not, deviate from this premise. The Remand Order stated that quantitative criteria needed to be supplied for the stakeholder process and the current proposal provides that criteria. No change made.		
Consolidated Edison Co. of NY, Inc.	No	Planned interruptions of Firm Demand in response to a Single Contingency (as directed in Footnote b of TPL-002 Table 1, and Footnote 12 of TPL-001-2), is not an acceptable corrective action to mitigate reliability issues on the BES system. The Interconnected System should be designed and operated with enough transfer capacity to be able to withstand, at a minimum, a single contingency event without service interruptions to customer load. Systems must be designed and operated so that the impact of any single contingency can be mitigated by re-dispatching available system resources without the need to implement load shedding.
Response: The SDT believes that special circumstances may exist where such actions as described in footnote 'b' are appropriate to meet the performance requirements of TPL. The footnote allows for such circumstances to exist in a controlled and prescribed environment where such usages can be discussed and resolved in an open and transparent process. No change made.		

Organization	Yes or No	Question 1 Comment
SDG&E	No	Table 1, footnote b of TPL-002 allows the use of load shedding for the loss of a single element (Category B) under certain circumstances. SDG&E has been against the proposed changes because of the addition of a stakeholder process that allows outside entities to make reliability decisions which we would be held accountable for.
Response: The SDT believes that the described process allows for open and transparent discussion of the potential use of footnote 'b' in the planning environment and disagrees that anything in the proposed footnote provides outside entities with the ability to make reliability decisions. No change made.		
Platte River Power Authority	No	Disagree with no change to the 75 MW threshold, but agree with the minor changes that were made since last posting. I request your consideration of a 300 MW threshold similar to that used in CIP-002 and EOP-004. Since there is a directive for some threshold, and in an attempt to reduce the likelihood of over-burdening smaller communities, the 300 MW level would be a more reasonable threshold for the BES.
Response: The SDT established the limit based on the results of the Section 1600 data request which clearly pointed to a 75 MW limit. While the SDT considered a higher limit value, the data collected does not justify such an action. No change made.		
ISO New England Inc	No	There are jurisdictional issues with the footnote and attachment as written. These will be described in further detail throughout this document. The footnote itself states, "An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events." A standard should not have requirements described as objectives, this language is extremely subjective.
Response: The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. And when such decisions do not involve any aspect of BES operation or reliability, such situations would not come under the purview		

Organization	Yes or No	Question 1 Comment
of footnote 'b' as standards only apply to the BES unless stated otherwise. However, in Order 693, FERC clearly stated that it has jurisdiction over matters that do involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote 'b' solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. No change made. The SDT does not believe that the stated objective serves as a requirement. No change made.		
MISO ITC JDRJC Associates LLC	No	MISO does not object to the changes made to the body of the footnote since the previous draft. However, as a general matter, MISO cannot support the current language of Footnote 12. Because the intent of the TPL standards is not to rely on non-consequential firm load shedding after a single contingency event, MISO does not agree that footnote b in NERC TPL-002-1 and/or footnote 12 in TPL-001-2 should be included in these standards. Nonetheless, if these footnotes are included, MISO agrees that there should be some limitation on how much firm load shed is allowed under these footnotes and would not object to the proposed 75 MW level if the footnotes are included.
Response: Thank you for your support. The SDT believes that special circumstances may exist where such actions as described in footnote 'b' are appropriate to meet the performance requirements of TPL. The footnote allows for such circumstances to exist in a controlled and prescribed environment where such usages can be discussed and resolved in an open and transparent process. No change made.		
Northeast Utilities	No	Northeast Utilities does not support the use of non-consequential demand interruption throughout the planning horizon. Even with the 75 MW limit, NU believes that this language seems to encourage operational workarounds and adds burdens for operators of the system. Lastly, NU believes this use of non-consequential load loss during the planning horizon is not consistent with planning a highly reliable bulk

Organization	Yes or No	Question 1 Comment
		electric system and thus does not support non-consequential load loss for planning purposes.
Response: The SDT believes that special circumstances may exist where such actions as described in footnote 'b' are appropriate to meet the performance requirements of TPL. The footnote allows for such circumstances to exist in a controlled and prescribed environment where such usages can be discussed and resolved in an open and transparent process. No change made.		
Hydro-Quebec TransEnergie	No	Hydro-QuÃ©bec TransÃ‰nergie (HQT) remains unconvinced that a MW threshold needs to be part of footnote 12. This is not a BES reliability issue but only a matter of service continuity to be addressed by TO/PA/RC with local regulatory authorities.
Response: The SDT Believes that the FERC Orders made it clear that the concept of dropping Non-Consequential Load for a N-1 Contingency must include MW thresholds. The SDT has made a change to the main body of the footnotes to address the concerns of non-US registered entities. **TPL-001-2a and TPL-002-1c** (main body of the footnote) **-** In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.		
Pacific gas and Electric Comapny	No	We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. Assigning a fixed "not to exceed" number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, "[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events". It is clear that the spirit

Organization	Yes or No	Question 1 Comment
		of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fix maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving “safe harbor” to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the “not to exceed” amount.
Response: The development of a standard that allowed for the use of footnote ‘b’ without quantifiable criteria was not acceptable to FERC as shown in the Remand Order. There is no ‘safe harbor’ up to the identified limit since it will be discussed in an open and transparent stakeholder process that includes applicable regulators. No change made.		
ACES Standards Collaborators Brazos	Yes	(1) We continue to disagree with the 75 MW capacity limit threshold. There is no need for a 75 MW cap because registered entities and local-level policy makers are in the best position to determine an appropriate capacity limit, as stated in the FERC order and in previous feedback. However, if the drafting team decides to move forward with a cap, we suggest using a cap that would reflect all data points from the Section 1600 data request to be under the threshold. The findings to the data request contained a data point at 75.2 MW, which would be over the proposed threshold. We understand this data point, in essence, has been omitted because the use of non-consequential load shedding for the 75.2 MW data point is expected to terminate soon. If the drafting team intends to use the data that represents the actual usage of footnote ‘b’ by planning coordinators, then the team should take into account the highest data point and adjust the threshold to at least 76 MW regardless of the length of time the data point is needed. Again,

Organization	Yes or No	Question 1 Comment
		local decision makers are better equipped to make this type of determination. (2) However, in the spirit of moving forward with this project we will support the changes and thank the drafting team for their efforts.
Response: The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. In Order 693, FERC clearly stated that it has jurisdiction over matters that do involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote 'b' solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. The SDT established the limit based on the results of the Section 1600 data request which clearly pointed to a 75 MW limit. While the SDT considered a higher limit value, the data collected does not justify such an action. No change made. Thank you for your support.		
Georgia Transmission Corp.	Yes	Since this question refers to both footnote b (TPL-002-1c) and footnote 12 (TPL-001-2a), and the changes to the footnotes are not identical, the question should be split into two. Regarding footnote b: An excerpt from footnote b reads "For purposes of this footnote, the following are not counted as Firm Demand (1) Demand directly served by the Elements removed from service as a result of the Contingency ..." However, what is being described is in fact Firm Demand (That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions) that is Consequential Load Loss (All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.). Therefore, why not use the terms Consequential Load Loss and Non-Consequential Load Loss? Regarding footnote 12: The replacing the NERC defined "Contingency" event with the undefined "planning" event necessitates a new definition.

Organization	Yes or No	Question 1 Comment
		The intent of the change is unclear.
Response: The issue is one of timing. The indicated terms are part of the proposed TPL-001-2 solution and were not in existence when TPL-002-1 was developed. Since the SDT cannot control how FERC will respond to the proposed solutions to this project, it is possible that TPL-002-1 could be approved prior to TPL-001-2. This would create considerable confusion as to the use of these terms. Therefore, the SDT wrote the proposed solutions separately. No change made. The wording change now makes the terminology consistent in both Table 1 and the text. No change made.		
Manitoba Hydro	Yes	Manitoba Hydro agrees that the changes add clarity to the footnote.
SERC EC Planning Standards Subcommittee	Yes	
Southwest Power Pool Reliability Standards Development Group Kansas City Power & Light	Yes	
Bonneville Power Administration	Yes	
MRO NSRF	Yes	
Duke Energy	Yes	
TVA Transmission Reliability Engineering and Controls	Yes	
Southern Company	Yes	
American Electric Power	Yes	
Ameren	Yes	

Organization	Yes or No	Question 1 Comment
Idaho Power Company	Yes	
Tacoma Power	Yes	
ITC	Yes	
Oncor Electric Delivery Company LLC	Yes	
Response: Thank you for your support.		

2. **Do you agree with the changes contained in Section II of Attachment 1? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments**

Summary Consideration: The SDT has responded to the individual comments and there are no changes proposed to the standards as a result of comments.

Organization	Yes or No	Question 2 Comment
ACES Standards Collaborators Brazos	No	(1) Thank you for making the changes to Section II of Attachment 1. We believe the modification of removing "assessments" and replacing it with "explanation" provides more flexibility regarding how a registered entity can demonstrate the impacts the health, safety and welfare of the community. (2) However, we still believe that the word "alleviate" in bullet 5 requires the same actions as the word "mitigate." There are instances where no action is required based on a variety of factors. We recommend the following: "Future plans, if necessary, to mitigate/alleviate the need for Non-Consequential Load Loss under footnote 12, unless a determination was made not to mitigate/alleviate, then an explanation why."
Response: Thank you for your support. This is an information section and not a requirement for a more permanent solution. Therefore, if there is no plan to alleviate then an entity simply documents that fact. No change made.		
MRO NSRF	No	The drafting team over specified the Section II stakeholder information process and continues to disregard comments that item 2b be removed from several utilities over several footnote "b" revisions. The goal of Attachment 1 as stated by the drafting team chair was to place "meaningful" parameters around footnote b. The words in 2b on "health, safety, and welfare" are beyond the scope of NERC standards, and are not defined sufficiently in the standard to make the

Organization	Yes or No	Question 2 Comment
		requirement meaningful. The NSRF recommends that if the drafting team doesn't eliminate 2b, they delete the words "on the health, safety, and welfare of the community" as going beyond NERC jurisdiction, FERC directives, and the SAR. The drafting team response that similar words exist in another standard is not a reason to the ambiguous words in the TPL Attachment 1.
Response: The SDT did not justify the retention of the subject phrase simply because similar words exist in another standard but because the burden and intent of the phrase in footnote 'b' is consistent with what entities are required to do in that other standard (the phrase is included in EOP-001 as part of a description of Load curtailment in Attachment 1 of EOP-001, which describes elements for consideration in developing emergency plans). The SDT believes that the changes made in this posting clarify the intent of this requirement. No change made.		
Hydro One Networks Inc.	No	As previously stated, we believe that the process presented in Section II is overly prescriptive. If a section that prescribes the information requirements for a stakeholder process is required, then for non-US entities this section should simply require that the process information requirements must be in accordance with the requirements of the applicable Regulatory Authority or Governmental Authority or its delegated agency that is responsible for local transmission and retail service in that jurisdiction.
Independent Electricity System Operator	No	No. The process presented in Section II is overly prescriptive. If a section that prescribes the information requirements for a stakeholder process is required, then for Canadian entities this section should simply state that any threshold should be established in a manner consistent with other service levels that apply to local transmission and retail service for the load to be curtailed, for the reasons described in Q1.
Response: The SDT has made a change to the main body of the footnotes to address the concerns of non-US registered entities. **TPL-001-2a and TPL-002-1c** (main body of the footnote) **-** In no case can the planned Firm Demand interruption under footnote		

Organization	Yes or No	Question 2 Comment
'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.		
Tri-State G&T	No	2. As stated previously, NERC Functional Model definitions for Planning Authorities and Transmission Planners do not include the types of activities being proposed in "Attachment 1." As written, this standard mandates functions on functional entities that are outside those defined by the NERC Functional Model. The SDT acknowledged this by stating that "the NERC Functional Model is a guideline for activities required of cited functional entities."As such, we still believe that obligations should not be required of entities outside of the NERC Functional Model descriptions.
Response: The SDT stands by its previous response to this comment posted for the comment period ending November 19, 2012.		
SCE&G	No	Comments previously submitted.
Response: Thank you for following the guidelines. Please see previous responses to this comment posted for the comment period ending November 19, 2012.		
Iberdrola USA	No	See comment to question 4 below.
Electric Reliability Council of Texas, Inc.	No	See response to question 4.
Response: See response to Q4.		
Entergy Services, Inc. (Transmission)	No	Attachment 1 is overly burdensome and unnecessary.
Response: The SDT believes that Attachment 1 is an appropriate response to the FERC Orders. Without specifics the SDT is unable to		

Organization	Yes or No	Question 2 Comment
provide a more detailed response to your concerns. No change made.		
Manitoba Hydro	No	Any assessment or explanation is only speculation. Is the requirement any different? Item 5 raises an expectation that footnote 12 can only be used on an interim bases - this should be clarified.
Response: The SDT believes that the changes made in this posting clarify the intent of this requirement. No change made. The SDT believes that, in general, the use of footnote 'b' to meet TPL performance requirements should be an interim solution. However, in certain circumstances, the SDT realizes that the solution may be permanent. The SDT does not believe that the wording only allows for interim use. If the solution is to be permanent, then that information should be disclosed as part of the stakeholder process. No change made.		
ISO New England Inc	No	Section II, 2.a, states that studies must address the estimated number and type of customers affected by Non-Consequential Load Shedding. The Transmission Planner in many cases will not be the appropriate entity to address these concerns. The Transmission Owner, Distribution Provider or Load Serving Entities would be the appropriate entities to address customer affects. Explaining effects on the "health, safety, and welfare of the community" is required under the footnote in Section II, 2.b. The same load could be shed directly as the consequence of a fault and no such assessment is required. In addition, Transmission Planners can shed radial load with no assessment of health and welfare. In addition to the practical considerations listed, once again here the standard infringes on Section 215 responsibilities where State authority over the "safety, adequacy and reliability of the electric system in that state" is mandated. This section should be deleted. Section II, requirements 3 and 4 discuss estimating frequency and duration of Non-Consequential Load Loss based on historical performance. The planning

Organization	Yes or No	Question 2 Comment
		process uses deterministic not probabilistic assessments. This section should be deleted.
Response: The SDT believes that the indicated information is easily obtained by the Transmission Planner and that, in some cases, the Transmission Planner may already have this information for other tasks and responsibilities. No change made. The SDT agrees that such information is not required in other circumstances involving allowed Consequential Load Loss. However, this situation is different in that it involves Non-Consequential Load Loss. No change made. The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. And when such decisions do not involve any aspect of BES operation or reliability, such situations would not come under the purview of footnote 'b' as standards only apply to the BES unless stated otherwise. However, in Order 693, FERC clearly stated that it has jurisdiction over matters that do involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote 'b' solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. No change made. The SDT believes that the information shown in Section II is necessary to allow stakeholders to understand the usage of footnote 'b'. No change made.		
MISO ITC JDRJC Associates LLC	No	Regarding the use of "explanation" in place of "assessment," MISO understands that the purpose of this change is to reduce the need for entities to hire expensive consultants and to incur other substantial costs in assessing demographic data and impacts on an affected area. However, as written, this word change potentially places more of a burden on responsible entities. An assessment is an analysis performed using available facts and data while an explanation implies full knowledge. MISO therefore recommends that "assessment" be retained and that a footnote explaining the meaning of that term be added. More generally, however, MISO has concerns regarding the use of a stakeholder process such as the one outlined in Attachment 1 and cannot support the Footnote or Attachment 1 at this time. Please refer to our comments under Question 4 for a more detailed description of these concerns.

Organization	Yes or No	Question 2 Comment
Response: The SDT believes that the changes made in this posting clarify the intent of this requirement. No change made. Please see response to Q4.		
Pacific gas and Electric Comapny	No	Suggest removing item 5, "A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction". Given that the "applicable regulatory authorities or governing bodies responsible for retail electric service issues" are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?
Response: Bullet #5 does not require specific attributes of the dispute resolution process. The SDT believes that the attributes of the dispute resolution process should be defined by the entity during the development of the stakeholder process. No change made.		
SDG&E	No	
Response: Without a specific comment, the SDT is unable to respond.		
SERC EC Planning Standards Subcommittee	Yes	
Northeast Power Coordinating Council	Yes	
Southwest Power Pool Reliability Standards Development Group Kansas City Power & Light	Yes	

Organization	Yes or No	Question 2 Comment
Bonneville Power Administration	Yes	
Duke Energy	Yes	
TVA Transmission Reliability Engineering and Controls	Yes	
Western Area Power Administration - Transmission Owner	Yes	
Southern Company	Yes	
Massachusetts Attorney General	Yes	
American Electric Power	Yes	
Ameren	Yes	
WAPA-RMR	Yes	
Idaho Power Company	Yes	
Platte River Power Authority	Yes	
Tacoma Power	Yes	
ITC	Yes	
Georgia Transmission Corp.	Yes	

Organization	Yes or No	Question 2 Comment
Oncor Electric Delivery Company LLC	Yes	
Response: Thank you for your support.		

3. **Do you agree with changes contained in Section III of Attachment 1? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The SDT has responded to the individual comments and there are no technical changes proposed to the standards as a result of comments. However, to avoid confusion, the SDT has deleted the duplicative statement in Section III regarding the 75 MW limit. And, the SDT made a grammatical change in Section III changing 'does' to 'do' to correct the grammar in the applicable sentences.

Section III – "… the applicable regulatory authorities or governing bodies responsible for retail electric service issues do~~es~~ not object …"

Organization	Yes or No	Question 3 Comment
MRO NSRF	No	The NSRF believes that the standards drafting team did clarify in the webinar that the 25 MW and 75 MW footnote "b" values were separate from interruptible load, and consequential load loss and would not be counted towards the 25 and 75 MW thresholds. However, the NSRF recommends that Attachment 1 also clearly contain an explicit statement "the 25 MW and 75 MW footnote "b" values are separate from consequential load loss, interruptible load, and are not to be counted towards the 25 MW and 75 MW thresholds."
Response: The SDT does not believe that this suggestion adds any clarity. No change made.		
Hydro One Networks Inc.	No	The process presented in Section III is overly prescriptive and duplicates information not necessary for its intended purpose. As stated in Q1, we disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard, and propose alternate language in our response to Q1. If this section is required to address a review of the use of footnote 12 to ensure that there are no wide-spread adverse reliability impacts on the bulk power system, then it should be limited to the information required for that purpose. Provided there is local support for the use of Non-Consequential Load Loss under footnote

Organization	Yes or No	Question 3 Comment
		12, only information items 6 and 8 from section II are relevant for this assessment-the remainder are not required for this section and should be deleted. Items 1 and 2 complicate this section and are unnecessary. They should be replaced by a phrase such as "for those planning events where the use of footnote 12 is referenced." We disagree with the need to submit this information to the ERO for a determination of whether there are any Adverse Reliability impacts caused by the use of Non-Consequential Load Loss. This will introduce a new type of review at the ERO that will create unnecessary delays and burden, and is inconsistent with (and not required for) all of the other performance requirements in the TPL standards. Submitting the analysis to the adjacent Planning Coordinators and Transmission Planners, and any functional entity that requests it, as called for in requirement R8 of TPL-001-2 should be sufficient.
Response: The SDT does not believe the section is overly prescriptive or duplicative as described below. No change made. Please see response to Q1. The SDT believes that the information shown in Section II is necessary to allow stakeholders to understand the usage of footnote 'b'. If local regulators require additional information they can always request it. While the ERO may not need all of the information in Section II to perform its Adequate Reliability Impact evaluation, the SDT wanted to minimize the burden on entities by allowing the submittal of an information package that already existed. The ERO is aware of the proposed responsibility and has accepted this role if the industry approves. The SDT believes that it is the responsibility of the ERO to assess Adverse Reliability Impacts and is not an appropriate role for adjacent planners. No change made.		
Iberdrola USA	No	See comment to question 4 below.
Electric Reliability Council of Texas, Inc.	No	See response to question 4.
MISO ITC	No	MISO does not object to the changes made to Section III. However, more generally, MISO has concerns regarding the use of a stakeholder process such as the one outlined in Attachment 1 and cannot support the Footnote or Attachment 1 at this

Organization	Yes or No	Question 3 Comment
JDRJC Associates LLC		time. Please refer to our comments under Question 4 for a more detailed description of these concerns.
Response: See response to Q4.		
Tri-State G&T	No	3. Previously, it was commented that it is unclear how section III of "Attachment 1" would be applied to entities that only deliver wholesale electric service and not retail electric service. The response provided by the SDT stated the following: The SDT believes that the wholesale customer will be one of the stakeholders included in the process and any use of footnote must go through the stakeholder process. No change made. If the wholesale customer is one of the stakeholders, the standard needs to add wholesale customers into the language as part of Attachment I. For example, it should read as follows: Coordinator must ensure that the applicable regulatory authorities, wholesale customers, or governing bodies responsible for retail electric service issues does not object to the use of Firm Demand interruptions under footnote 'b'...
Response: The SDT believes that the planning entity has the best understanding of who an affected stakeholder will be and that any attempt to codify a list of such stakeholders in the proposed standards could lead to errors due to the necessity of having to adopt a one size fits all approach. No change made.		
Western Area Power Administration - Transmission Owner	No	See answer to Question 1.
WAPA-RMR	No	See response to Question 1.
Platte River Power Authority	No	See answer to Question 1.
Response: See response to Q1.		

Organization	Yes or No	Question 3 Comment
Massachusetts Attorney General	No	Don't buy the 75 MW or the 25 MW thresholds.
Response: The SDT established the values based on the results of the Section 1600 data request. While the SDT considered other values, the data collected did not justify such an action. No change made.		
Entergy Services, Inc. (Transmission)	No	Attachment 1 is overly burdensome and unnecessary.
Response: With no specifics provided, the SDT is unable to respond further. However, the SDT does not believe the process to be overly burdensome or unnecessary. No change made.		
SCE&G	No	Comments previously submitted.
Response: Thank you for following the guideline. Please see previous responses to this comment posted for the comment period ending November 19, 2012.		
Independent Electricity System Operator	No	The process presented in Section III is overly prescriptive and requires information not necessary to the intended purpose. As stated in Q1, we disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard, and propose alternate language as stated in Q1 comments and supporting reasons. If this section must deal with a review of the use of footnote 'b'/'12' to ensure that there are no widespread adverse reliability impacts on the bulk power system, then it should be limited to the information required for that purpose. Provided there is local support for the use of Non-Consequential Load Loss under footnote 'b'/'12', only information items 6 and 8 from section II are relevant for this assessment-the remainder are not required for this section and should be deleted. The use of footnote 'b'/'12' should not be limited to the Near-Term Planning Horizon. We propose that the words "in Year One of the Planning Assesssment" be deleted.

Organization	Yes or No	Question 3 Comment
		Items 1 and 2 complicate this section and are unnecessary. They should be replaced by a phrase such as "for those planning events where the use of footnote 'b'/'12' is referenced". We disagree with the need to submit to the ERO for a determination of whether there are any adverse reliability impacts caused by the use of Non-Consequential Load Loss. This will introduce a new type of review at the ERO that will create unnecessary delays and burden, and is inconsistent with and not required for all of the other performance requirements in the TPL standards. Submitting the analysis to the adjacent Planning Coordinators and Transmission Planners, and any functional entity that requests it, as called for in requirement R8 of TPL001-2 should be sufficient.
Response: The SDT does not believe the section is overly prescriptive or duplicative as described below. No change made. Please see response to Q1. The use of the footnote is not limited to the Near-Term Transmission Planning Horizon since the main body of the footnote states that the footnote may be utilized "… throughput the planning horizon…". An entity has the freedom to make a business decision concerning the use of footnote 'b' compared to other alternatives. An entity is free to determine when they want to assure that the local regulator does not object but it must do so no later than Year One of the Planning Assessment. No change made. The SDT believes that items 1 and 2 are needed to describe when an entity must assure that there are no regulatory objections. No change made. While the ERO may not need all of the information in Section II to perform its Adequate Reliability Impact evaluation, the SDT wanted to minimize the burden on entities by allowing the submittal of an information package that already existed. The ERO is aware of the proposed responsibility and has accepted this role if the industry approves. The SDT believes that it is the responsibility of the ERO to assess Adverse Reliability Impacts and is not an appropriate role for adjacent planners. No change made.		
Pacific gas and Electric Comapny	No	We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative

Organization	Yes or No	Question 3 Comment
		process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the "applicable regulatory authorities or governing bodies responsible for retail electric service issues".
Response: The SDT believes that the information shown in Section II is necessary to allow stakeholders to understand the usage of footnote 'b'. No change made.		
SDG&E	No	
Response: Without a specific comment, the SDT is unable to respond.		
ISO New England Inc		The footnote states "Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues does not object to the use of Non-Consequential Load Loss under footnote 12 if either...". Section 215 of the Federal Power Act clearly delineates Federal, State and Local authority. State and Local requirements should not be introduced into a NERC standard. In addition to the jurisdictional issues, proving that the "applicable regulatory authority or governing body" does not object is more difficult than proving that they simply approved the use of non-consequential load loss. The SDT should remove all references to State and Local authority from the standard. Overall, the order of Section III is also notable. During year, two through ten of the overall planning horizon the standard allows for Non-Consequential Load Loss without approval. In the first year of the assessment, approval becomes required for Non-Consequential Load Loss. At this point, it is too late to allow for any other alternative.

Organization	Yes or No	Question 3 Comment
		The Regional Entities with NERC oversight perform periodic audits and require self-certification of the planning process. By virtue of the audit and self-certification process, NERC has the ability to monitor the use of Non-Consequential Load Loss in planning assessments. State and Local approval of practices called for in ERO Standards is inappropriate. In addition to being notable for the year one timing, Section III seems incomplete. In the case where there is objection to Non-Consequential Load Shedding, the process appears to end without resolution.
Response: In Order 693, FERC clearly stated that it has jurisdiction over matters that involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote 'b' solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. The footnote does not place requirements on local regulators but rather provides them an opportunity to participate in the stakeholder process. No change made. An entity has the freedom to make a business decision concerning the use of footnote 'b' compared to other alternatives. An entity is free to determine when they want to assure that the local regulator does not object but it must do so no later than Year One of the Planning Assessment. No change made. Without the details now contained in the proposed footnote, there is no guarantee that NERC would have the information to monitor the use of Non-Consequential Load Loss. The footnote does not place requirements on local regulators but rather provides them an opportunity to participate in the stakeholder process. No change made. If there is an objection by the regulators, then an entity cannot utilize footnote 'b' as proposed as part of the Corrective Action Plan for Year One. No change made.		
Ameren	Yes	We find no substantive changes to section III, and still believe that no objection from a regulatory body requires, at a minimum, a tacit approval.
Response: The SDT believes that there are a variety of practices employed by regulatory bodies. Therefore, it is determined by the planning entity and the applicable regulatory bodies as to how to show 'no objection'. No change made.		

Organization	Yes or No	Question 3 Comment
SERC EC Planning Standards Subcommittee	Yes	Change "does" to "do" in the last sentence of the first paragraph and in the first sentence of the last paragraph in Section III of Attachment 1.
Response: The SDT agrees and has made the suggested grammatical change. **Section III** – "... the applicable regulatory authorities or governing bodies responsible for retail electric service issues do~~es~~ not object …"		
Northeast Power Coordinating Council	Yes	
Southwest Power Pool Reliability Standards Development Group Kansas City Power & Light	Yes	
Bonneville Power Administration	Yes	
ACES Standards Collaborators Brazos	Yes	
Duke Energy	Yes	
TVA Transmission Reliability Engineering and Controls	Yes	
Southern Company	Yes	
American Electric Power	Yes	

Organization	Yes or No	Question 3 Comment
Idaho Power Company	Yes	
Tacoma Power	Yes	
ITC	Yes	
Georgia Transmission Corp.	Yes	
Oncor Electric Delivery Company LLC	Yes	
Response: Thank you for your support.		

4. If you have any other comments on this Standard that you haven't already mentioned above, and that are not simply reiterating previous comments that the SDT has already responded to, please provide them here:

Summary Consideration: The SDT has responded to the individual comments and there are no changes proposed to the standards as a result of comments. However, the SDT did uncover a typo that has been corrected as shown below.

TPL-002-1c: footnote 'b' – "…For purposes of this footnote, the following are not counted as Firm Demand~~t~~: (1) …"

Organization	Yes or No	Question 4 Comment
Hydro-Quebec TransEnergie	No	HQT still considers that the non application of footnote 12 to categories P2 (breaker fault), P4 (stuck breaker) and P5 (failure of a non redundant relay) is not correct, when the footnote is applied to other categories such as P3, P6 and P7 (loss of double-circuit lines). The SDT has indicated that the applicability of footnote 12 to categories P2, P4 and P5 is not included in Project 2012-11. However, looking at related Project 2006-02 where footnote 12 was brought up to Table 1, the matter of applicability was not discussed in detail and the SDT did not clearly explain why Non-Consequential Load Loss was not allowed for contingencies less frequent than those for which it is allowed (internal breaker faults or stuck breakers are less probable than double-circuit line faults). Discussion on this matter should not be dismissed.
Response: Table 1 in the proposed TPL-001-2 was previously approved by industry through the standards development process. The Board of Trustees has also previously approved this proposed standard. Discussions on the applicability of footnote 12 in that standard were held during Project 2006-02 and are not part of this proceeding. No change made.		
Bonneville Power Administration	No	
Duke Energy	No	

Organization	Yes or No	Question 4 Comment
American Electric Power	No	
SDG&E	No	
Idaho Power Company	No	
Platte River Power Authority	No	
SCE&G	No	
Oncor Electric Delivery Company LLC	No	
Pacific gas and Electric Comapny	No	
Response: Without a specific comment, the SDT is unable to respond.		
ACES Standards Collaborators Brazos	Yes	(1) In regard to the changes relating to Demand-Side Management, we agree with the wording, "For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of a Contingency, or (2) Interruptible Demand or Demand-Side Management Load." However, the most recent change has created some confusion by replacing "or" with "and" that potentially and inadvertently may exclude the use of DSM in all locations but on the facilities removed from service. This would render DSM ineffective. Now, the both (1) and (2) must occur in order to not be counted as Firm Demand. We recommend changing the wording back to "or" so each option (1) OR (2) is independently excluded from Firm Demand for footnote b. Connecting the options with the word "and" changes the meaning and requires entities to meet both option (1) and option (2) to be excluded from Firm Demand. Demand directly served by the Elements removed from service as a result of a Contingency should be

Organization	Yes or No	Question 4 Comment
		excluded, as should Interruptible Demand or Demand-Side Management Load regardless of its location. A registered entity does not need to have both for the exclusion. (2) Thank you for the opportunity to comment.
Response: The SDT does not agree that 'and' excludes the use of both items 1 and 2 since this is a list of options. However, while researching your suggestion, the SDT discovered a typo in the language when the previous red-line was converted to a clean copy. This has been corrected as shown. **TPL-001-2c: footnote 'b'** – "…For purposes of this footnote, the following are not counted as Firm Demand~~t~~: (1) …"		
Hydro One Networks Inc.	Yes	As previously stated in our response to Question #1, Hydro One would like to reiterate our position presented during the initial comment period. We believe that the SDTs response to our initial comments did not correctly address the issues because it did not recognize the Reliability Standards framework that is effective in the Province of Ontario and possibly other Canadian provinces.
Response: Please see the response to Q1.		
MISO ITC JDRJC Associates LLC	Yes	As previously stated, it is the general intent of the existing TPL-002-1 standard and proposed TPL-001-2 standard to not rely on any shedding of Non-Consequenital Load to meet a single contingency event. Accordingly, MISO submits that footnote b of TPL-002-1 and footnote 12 of TPL-001-2 should be struck. However, in the event that the footnotes in question are not eliminated, the footnote should be narrowly focused only on those situations for which the original footnote was developed, i.e., the interruption of service to radial customers or some local area Network customers connected to or supplied by the Faulted element or by the affected area, where the overall reliability of the interconnected transmission system is not impacted. MISO therefore proposes the following alternate language for footnote b and footnote 12 to ensure it is not misapplied:"An objective of the planning process is to avoid Non-Consequential Load Loss following Contingency

Organization	Yes or No	Question 4 Comment
		events. In limited circumstances, Non-Consequential Load Loss may be needed within the planning horizon to ensure that BES performance requirements are satisfied. However, Non-consequential Load shed cannot be used to avoid cascading outages or to maintain system stability. Non-consequential load shed also cannot be used to avoid a thermal loading or voltage limit violation on an extra high voltage (EHV) facility. When Non-Consequential Load Loss is utilized within the transmission planning horizon to address BES performance requirements, such interruption cannot exceed 75 MW and is limited to the following circumstances: o Non-consequential Load shed is allowed for load served by a radial transmission line to avoid voltage limit violations on the radial transmission line following a single contingency event. o Non-consequential load shed is allowed for load within a local area served by not more than two Transmission Circuits and/or Transformers to avoid a thermal loading issue or voltage issue within the local area, including the Transmission Circuits and/or Transformers directly supplying the local area, for a loss of a single element within the local area, including one of the Transmission Circuits or Transformers directly supplying the local area, so long as there are no thermal loading or voltage violations outside the local area." MISO believes the language above would ensure the continuing reliability of the Bulk Electric System by limiting load shed and violations that require load shed to radial areas or areas that would be served radially following the single contingency. In addition, MISO has significant concerns regarding use of a stakeholder process to determine if non-conseqeuntial load shedding is appropriate following a single contingency event, as expressed in MISO's comments on previous drafts of this Project. In particular, MISO has concerns regarding whether such a stakeholder process could be sufficiently open and transparent given the many, competing interests of the responsible entity and affected stakeholders. Without such sufficient openness and transparency, it is likely that stakeholder processes will not result in consistent determinations of the appropriateness of the application of footnote b in NERC TPL-002-1 and/or footnote 12 in TPL-001-2. Stated differently, MISO is concerned that such stakeholder processes will always be subject to the

Organization	Yes or No	Question 4 Comment
		biases of the participating parties, with the sheer number of parties determining the outcome of the process. As an example, should a particular process be dominated by parties that may be responsible for payment of upgrades but that are not impacted by the alternative load shed, those stakeholders impacted by the alternative load loss would be relegated to a minority position, resulting in majority-imposed stakeholder decisions to shed load. On the other hand, if the stakeholder process is limited to only the stakeholders directly impacted by the proposed load shed, to the extent those stakeholders pay only a small part of the upgrade costs, they will always choose to avoid load shed - even if such decision requires a potentially costly upgrade. Consequently, MISO has concerns that the inclusion of a requirement for a fair and impartial stakeholder process to determine if and when load shed is acceptable to assist in satisfying a single contingency standard is not realistically attainable. MISO therefore recommends that Attachment I be eliminated and that the footnotes either be eliminated or replaced with the modified version above.
Response: The SDT believes that the suggested language adopts a one-size fits all approach that is not conducive to a continent-wide standard. The footnote allows for circumstances outside of the suggested language scenarios, as well as those described in the suggestion, to be resolved utilizing an open and transparent process. No change made. The SDT believes that the inclusion of stakeholders including regulators provides an appropriate method for addressing the issues that the commenter has raised. No change made.		
BC Hydro	Yes	BC Hydro appreciates the efforts of the SDT in revising standards TPL-002-1c - System Performance Following Loss of a Single BES Element (footnote b) and TPL-001-2a - Transmission System Planning Performance Requirements (footnote 12). BC Hydro votes YES in support of this ballot and wishes to provide the following two comments: 1.At this time BC Hydro has concerns about the level of stakeholder consultation that might be required as a result of the implementation of this standard and will bring this concern to the attention of our regulator if necessary. 2.At this time BC Hydro has concerns about the instances for which regulatory

Organization	Yes or No	Question 4 Comment
		review of non-consequential load loss under footnote 12 is required and will discuss those with our regulator if necessary.
Response: The SDT appreciates your overall support. In addition, please see the changes shown in Q1 for non-US registered entities.		
Central Lincoln Flathead	Yes	Central Lincoln has not paid much attention to this standard, since it is not applicable to this entity's registered functions. However, we are disturbed by the direction the standard is taking. The slides from the recent webinar (http://www.nerc.com/docs/Standards/dt/footnoteb_webinar_20130108_final.pdf) state that "The 75 MW cap will require construction of major Transmission projects." This is in direct conflict with the definition of "reliability standard" as provided in section 215 of the FPA where it states "...the term does not include any requirement to enlarge such facilities or to construct new transmission capacity..." The webinar slide does offer alternatives to construction, but we don't see those providing any reliability benefit. Some of the suggestions apparently only relate to contract language, which cannot possibly relate in any way to "reliable operation" as defined in section 215. Central Lincoln is is concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal power Act and into customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions.
Response: The statement from the January 8, 2013 webinar is a concern that industry had raised during the course of the project, which the SDT had captured on a slide in order to respond to the concern during the webinar. The SDT pointed out that building is not the sole source of remedy for the situation and provided specific examples in the webinar (http://www.nerc.com/docs/Standards/dt/footnoteb_webinar_20130108_final.pdf (slide 13)). In Order 693, FERC clearly stated that it has jurisdiction over matters that do involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote 'b' solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. No change made.		
Electric Reliability Council of Texas, Inc.	Yes	ERCOT believes that the revisions to the footnote b attachment are an improvement from the previous version. However, ERCOT does not believe that the

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td></td><td></td><td>SDT provided a technical rationale for disagreeing with the comments that we previously submitted. We fundamentally disagree with the approach of defining a stakeholder process in the attachment to a footnote in a reliability standard. While footnotes and attachments have been used in other standards we believe that this application is not appropriate.

ERCOT believes that the footnote should be removed altogether as it does not meet the objectives of FERC Order 693. We also believe that FERC did not mandate that a stakeholder process be used. As stated in the January 8 NERC Industry Webinar, 90% of planning entities have not used the existing footnote b over a planning horizon of 13 years. To incorporate an attachment to a footnote with a complicated and prescriptive stakeholder process to address a few instances seems to be a least common denominator approach to planning which is opposed to FERC's direction. Consistent with the approach of TPL-001-2, ERCOT recommends raising the bar on reliability and removing the footnote from the standard.</td></tr>
<tr><td colspan="3">Response: The SDT used the Board of Trustees approved standard as a starting point for this draft. FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. The use of footnotes and attachments is an acceptable mechanism for use in Reliability Standards and both mechanisms have been used before. No change made.

The SDT believes that special circumstances may exist where such actions as described in footnote 'b' are appropriate to meet the performance requirements of TPL. The footnote allows for such circumstances to exist in a controlled and prescribed environment where such usages can be discussed and resolved in an open and transparent process. No change made.</td></tr>
<tr><td>Southern Company</td><td>Yes</td><td>Footnote b contains no technical basis for allowing load dropping. It is completely based on an administrative procedure. This is not responsive to paragraphs 17 and 32 of the FERC remand order. A technical basis has to be proposed. The "temporarily radial" concept that was proposed in earlier drafts will address this problem. It will give a technical basis for when load dropping would be allowed. If a technical basis is developed like FERC requires, then there is no need for a</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
		stakeholder process. The stakeholder process is not a bright line criteria which can be enforced; it will change depending on the make-up of stakeholders and therefore create inconsistencies across the grid. This approach should never be used in a reliability standard. NERC adopted the ANSI standard process as the bench mark in developing its reliability standards. ANSI does not use stakeholder processes. We propose that the stakeholder process be eliminated. Create a technical basis for when load dropping can be utilized. Keep the 75 MW maximum amount of load that can be dropped.
Response: The SDT believes that the proposed approach is responsive to the Remand Order since it contains quantitative criteria and a more well-defined stakeholder process. The temporary radial concept was discussed by the SDT but abandoned due to industry comments that pointed to the difficulties in adopting this concept on a continent-wide basis. The attachment is enforceable as a clear set of expectations has been described. The conclusions reached as a result of following the stakeholder process may be different due to local configurations, constraints, and expectations of applicable regulatory bodies. No change made.		
WAPA-RMR	Yes	I believe that the 75 MW limit is abetrary and could be too low given particular circumstances, like the maginitude of recent load growth in the area, regulatory hurdles in building new transmission, etc. I also believe that the Attachment 1 stakeholder process is not needed, since it is already covered by the FERC Ordered 890 planning process.
Western Area Power Administration - Transmission Owner	Yes	Western believes that the 75 MW limit is arbitrary and could be to low given particular circumstances, like the magnitude of recent load growth in the area, regulatory hurdles in building new transmission, etc. We also believe that the Attachment 1 stakeholder process is not needed, since it is already covered by the FERC Order 890 process.
Response: The SDT established the limit based on the results of the Section 1600 data request which clearly pointed to a 75 MW limit. While the SDT considered a higher limit value, the data collected does not justify such an action. The SDT used the Board of Trustees approved standard as a starting point for this draft. FERC remanded the standard; not because it contained a stakeholder		

Organization	Yes or No	Question 4 Comment
process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. The use of footnotes and attachments is an acceptable mechanism for use in Reliability Standards and both mechanisms have been used before. No change made. The phrase in Section I: "The responsible entity can utilize an existing process or develop a new process" was designed to allow an entity to use an existing process as long as it meets the requirements shown in Attachment 1. No change made.		
Entergy Services, Inc. (Transmission)	Yes	If Attachment 1 must remain, Entergy would support the SERC PSS suggestion to limit the application of Attachment 1 (the stakeholder process) to only those situations where the non-consequential load at risk is above 25MW.
Response: As approved by the Board of Trustees, all utilizations of footnote 'b' required the use of the stakeholder process. The current proposal does not, and should not, deviate from this premise. The Remand Order stated that quantitative criteria needed to be supplied for the stakeholder process and the current proposal provides that criteria. No change made.		
Manitoba Hydro	Yes	Manitoba Hydro cannot support the Footnote B attachment which imposes a stakeholder process not required in Manitoba.
Response: The open and transparent stakeholder process is a new requirement for all entities in response to the need to clarify footnote 'b'. No change made.		
seattle city light	Yes	SCL abstains from voting on the revisions to footnote "b" in TPL-002-1c and the corresponding footnote 12 of TPL-001-2.Â SCL is concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal power Act and into customer service issues that are better served by, and under the jurisdiction of,Â state and local utility boards and commissions (for details on SCL's concerns please see the comments submitted during the initial ballot).Â However, in the spirit of moving this process forward, SCL will not vote against the revised footnotes.
Public Utility District No.1 of	Yes	The Public Utility District No.1 of Snohomish County will abstain from voting on the

Organization	Yes or No	Question 4 Comment
Snohomish County		revisions to footnote "b" in TPL-002-1c and the corresponding footnote 12 of TPL-001-2. The Public Utility District No.1 of Snohomish County is concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal power Act and into customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions (for details on the Public Utility District No.1 of Snohomish County's concerns please see the comments submitted during the initial ballot). However, in the spirit of moving this process forward, the Public Utility District No.1 of Snohomish County will not vote against the revised footnotes.
ISO New England Inc		In summary, this standard as proposed has misplaced jurisdictional authority under Section 215 of the Federal Power Act. The removal of references to State and Local authorities in the standard is required.
National Grid	Yes	We are accepting the standard as written because our current practices are better then the prescribed maximum limit. However, we believe the appropriate limit should be determined on a case by case basis with the state regulator input. This standard as written, does give us the flexibility to do this.
Response: The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. And when such decisions do not involve any aspect of BES operation or reliability, such situations would not come under the purview of footnote 'b' as standards only apply to the BES unless stated otherwise. However, in Order 693, FERC clearly stated that it has jurisdiction over matters that do involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote 'b' solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. No change made.		
New Brunswick System Operator		We do not agree with setting a MW limit for non-consequential load loss. The allowable amount should be determined and approved by the jurisdiction of the area(s) whose load is affected. The intent of the TPL standard and this footnote is to ensure that if non-sequential load loss is accounted for or relied up to ensure BES reliability (as assessed in the planning horizon), that such a decision needs to be

Organization	Yes or No	Question 4 Comment
		approved by the appropriate jurisdiction
Response: Please see the changes shown in Q1 to account for jurisdictional differences for non-US registered entities.		
MRO NSRF	Yes	Some entities remain concerned over a potential conflict and mismatch of impacts introduced by Section III and the inclusion of non-regulated stakeholders versus NERC regulated entities. There was not a FERC directive to include section III. Section III overreaches the intent of the FERC order and the SAR to meet the FERC directive. The drafting team should show the specific FERC requirement and words in Order 693 that requires non-NERC regulatory reviews. The drafting team technically responded to a request that Section III be removed, but avoided the the fundamental issue. The fact that some existing non-NERC regulatory bodies may already have a consistent practice is not a reason to include non-NERC entities into a NERC framework. This creates a fundamental mismatch between NERC regulated entities that must follow NERC standards and stakeholders that are not compelled by NERC requirements. If Section III is not deleted, it is recommended that wording be added to allow the existing FERC Order 890 stakeholder meeting process be used to meet Attachment 1. Regulators attend these meetings and all stakeholders (including regulators) could be asked for their objections. If there was no response or a “lack of dissent”, this would be documented as meeting Attachment 1 to allow the use of footnote “b” without additional special procedures.
Response: The phrase in Section I: “The responsible entity can utilize an existing process or develop a new process” was designed to allow an entity to use an existing process as long as it meets the criteria shown in Attachment 1. No change made.		
Iberdrola USA	Yes	The reasons for the “negative” vote are enumerated in our prior comments. In summary: 1. Attachment 1 is cumbersome and inappropriate, and should be stricken entirely. 2. All non-consequential load loss for all single-element contingencies should be temporary, with an action plan to avoid such load loss in the future.

Organization	Yes or No	Question 4 Comment
		3. All actions following single-element contingencies should be an attempt to restore lost customer service, not interrupt more customers.
Response: The transparency provided by the stakeholder process will meet the regulatory guidance provided on this issue. The limited use of footnote 'b' as shown by the data collected in response to the Section 1600 data request indicates relatively few instances where footnote 'b' would be used. For this reason, the SDT believes that the proposed approach strikes the right balance. . No change made. The SDT agrees that this is often the normal course of action. However, the SDT has not mandated this course of action since there could be circumstances that may arise where the continued use of footnote 'b' may be the best over-all solution for all concerned. No change made. The SDT believes that special circumstances may exist where such actions as described in footnote 'b' are appropriate to meet the performance requirements of TPL. The footnote allows for such circumstances to exist in a controlled and prescribed environment where such usages can be discussed and resolved in an open and transparent process. No change made.		
Southwest Power Pool Reliability Standards Development Group Kansas City Power & Light	Yes	Under section II items 3 and 4 the wording (frequency and duration) seems to implicate that the planners will be determining these events in a probabilistic manor. If the probability of these events is anything other than 0 planners will have to accommodate for those events in their planning assessments regardless of how small the probability is for that event.
Response: The SDT does not agree that the wording requires a probabilistic determination. The planning method utilized to make the determination is left up to the planner however this information is necessary to allow stakeholders to understand the usage of footnote 'b'. No change made.		
ITC	Yes	While ITC is voting yes for this "successive ballot", we are doing so in the interest of ensuring that TPL 001-2 becomes fully effective as soon as possible. TPL001-2 is a major improvement to previous standards and insuring it becomes fully effective is important to ITC and the industry. However, we have concerns that we would like to be noted. Because footnote B has been highlighted and expanded, there is the possibility of future "unintended consequences". It is highly likely that interveners

Organization	Yes or No	Question 4 Comment
		or others may attempt to stop or slow down needed corrective action plans, that do not rely on load shedding, by suggesting that planners use this stakeholder process before proposing projects. We suggest both NERC and FERC be prepared to deal with these unintended consequences. We also concur in entirety with the comments MISO is proposing to make for this project. They are consistent with past comments ITC has made and do discuss in some detail the potential “unintended consequences” this detailed footnote may cause.
Response: The SDT believes that special circumstances may exist where such actions as described in footnote ‘b’ are appropriate to meet the performance requirements of TPL. The footnote allows for such circumstances to exist in a controlled and prescribed environment where such usages can be discussed and resolved in an open and transparent process. No change made.		
Xcel Energy	Yes	While we are not satisfied with the responses to our previous comments, we have chosen to not reiterate them here. Instead, we feel that the need to continue with any modification to Footnote b seems moot considering FERC's recent approval of the revised BES definition. Specifically, we believe exclusions E1 and E3, regarding radial systems and local networks, resolves FERC's original directive on ambiguity with footnote b. We recommend the team consider abandoning this project, and request that NERC staff request relief from FERC on the related directives, as they have been overcome by the modified BES definition.
Response: The SDT believes that there may be portions of the BES, even with the proposed revised BES definition, where it may still be appropriate to address performance issues using footnote ‘b’ for Non-Consequential Load Loss. No change made.		
Independent Electricity System Operator		(1) The IESO reiterate its support for allowing load interruption for a single contingency with sufficient review/oversight and under acceptable conditions, including no widespread adverse impact on the reliability of the interconnected bulk power system. The reliability aspects (BES performance requirements) should be reviewed for acceptability by the adjacent Planning Coordinators and Transmission Planners. However, issues pertaining to economics or externalities which may not be directly reliability-related are always available for review and

Organization	Yes or No	Question 4 Comment
		debate by the stakeholders via the regulatory processes and subject to approval by the regulatory authority of each jurisdiction (including those in Canada and Mexico). (2) Furthermore, we request that Table 1 of TPL-001-3 (previous TPL-001-2 approved by NERC BOT) be corrected for EHV contingencies in P2, P4 and P5 categories to allow the application of footnote 'b'/'12' that is allowed for the P1 events. Events in P2, P4, and P5 can involve more elements and can be more onerous and stressful to the system than the P1 events, and if use of footnote 'b'/'12' is permitted in the less stressful P1 events, it should also be permitted in P2, P4 and P5 events. There continues to be confusion as to this inconsistency, and to how this is to be applied (as discussed at the last webinar). (3) We suggest that NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve it. Accordingly, we believe that the focus of footnote 'b', and footnote 12 should be that interruption of load must not have a widespread, adverse impact on the reliability of the interconnected bulk power system. A continent-wide standard should not concern itself with the reliability of supply or supply continuity for local load, as that is the responsibility of the applicable regulatory authority or its agencies responsible for local transmission and retail service over the load to be curtailed. As mentioned above, NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve it. In this regard, we believe that Attachment 1 is not necessary because it prescribes a process which goes beyond the outcome of the standard and dictates how stakeholdering must be carried out. The individual jurisdiction should establish the process for ensuring compliance with the standard and decide to what extent a stakeholdering process is necessary to establish the acceptable level of load rejection for the area in a manner consistent with local transmission established service levels. (4) The process presented in Section I is overly prescriptive. If a section that prescribes the principles of a stakeholder process is required, then for Canadian entities this section should simply state that any threshold should be established in

Organization	Yes or No	Question 4 Comment
		a manner consistent with other service levels that apply to local transmission and retail service for the load to be curtailed, as described in Q1 and for the reasons stated therein. Corrective action plans can rarely be implemented in a one-year time frame, and in some cases, limited use of Non-consequential Load Loss will be preferable to unaffordable transmission enhancements, therefore we believe that the use of footnote ‘b’/’12’ should not be limited to the Near-Term Transmission Planning Horizon. We propose that the phrase “the Near-Term Transmission Planning Horizon of” be deleted from the opening paragraph.
Response: The SDT believes that it is the responsibility of the ERO to assess Adverse Reliability Impacts and is not an appropriate role for adjacent planners. The proposed stakeholder process allows all stakeholders, including regulators, will have the necessary information required for the indicated reviews. No change made. Table 1 in the proposed TPL-001-2 was previously approved by industry through the standards development process. As shown by this approval, the SDT and the industry disagree that there is a technical irregularity in Table 1. The Board of Trustees has also previously approved this proposed standard. Discussions on the applicability of footnote 12 in that standard were held during Project 2006-02 and are not part of this proceeding. No change made. The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. And when such decisions do not involve any aspect of BES operation or reliability, such situations would not come under the purview of footnote ‘b’ as standards only apply to the BES unless stated otherwise. In addition, please see the changes shown in Q1 to address jurisdictional concerns for non-US registered entities. No change made. Please see the changes shown in Q1 to address jurisdictional concerns for non-US registered entities. The use of the footnote is not limited to the Near-Term Transmission Planning Horizon since the main body of the footnote states that the footnote may be utilized “… throughput the planning horizon…”. No change made.		
SERC EC Planning Standards Subcommittee		We continue to recommend that up to 25 MW of planned interruption be allowed without triggering the need for a stakeholder process. We believe that this simplification would be less burdensome and would enhance industry acceptance of the revision, while still meeting regulatory guidance. The comments expressed

Organization	Yes or No	Question 4 Comment
		herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
TVA Transmission Reliability Engineering and Controls		We recommend that up to 25 MW of planned interruption be allowed without triggering the need for a stakeholder process. We believe that this simplification would be less burdensome and would enhance industry acceptance of the revision, while still meeting regulatory guidance.
Response: As approved by the Board of Trustees, all utilizations of footnote 'b' required the use of the stakeholder process. The current proposal does not, and should not, deviate from this premise. The Remand Order stated that quantitative criteria needed to be supplied for the stakeholder process and the current proposal provides that criteria. No change made.		
Tacoma Power		While Tacoma Power appreciates NERC's attempt to address both footnotes with the same drafting team, Tacoma Power is voting negative on the revisions to footnote "b" in TPL-002-1c and the corresponding footnote 12 of TPL-001-2. However, Tacoma Power would vote affirmative if a re-circulation ballot was limited strictly to footnote "b" in TPL-002-1c. TPL-001-2 considered new types of outages not considered by TPL version 1, such as P2-1. Although TPL-001-2 was approved by the industry, the proposed modifications to footnote 12 in TPL-001-2 are significantly more onerous than footnote 12 in TPL-001-2. Furthermore, since TPL-001-2 is not yet enforceable, some Transmission Planners still do not realize that automatic relay actions are considered Non Consequential Load Loss. In addition, Tacoma Power identified over 100 MW of load in multiple locations that would be shed in accordance with footnote 12 in TPL-001-2. Unfortunately, the structure of the Section 1600 data request did not allow for the submittal of footnote 12 related data. Since it is clear that the potential impact of the footnote 12 revision has not been addressed due to the compressed timeline, Tacoma Power believes that by separating the two standards, NERC can meet the FERC mandated deadline for footnote b while still continuing the drafting process to achieve true industry consensus on footnote 12. Please note that FERC orders 693 and 762 require

Organization	Yes or No	Question 4 Comment
		addressing only footnote "b" by the using the Expedited Standards Development Process. Earlier FERC orders discuss "single contingencies" as type Category B in TPL-002-1; FERC has not addressed Non Consequential Load Shedding for the lower probability "single contingencies" (i.e. P2-1) in TPL-001-2. Approving the revisions to footnote 12 would result in negligible reliability gains at an unreasonable cost for customers on the fringes of the power system, without affording local jurisdictional cost benefit analysis. Tacoma Power is also concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal Power Act. These revisions tread on customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions. For details on Tacoma Power's concerns please see the comments submitted during the initial ballot. However, in the spirit of moving this process forward, Tacoma Power would vote to approve the revisions to solely TPL-002-1c if balloted separately from TPL-001-2.Tacoma Power appreciates the opportunity to provide comments, and thanks you for consideration of our comments.
Response: Any information gleaned from a Section 1600 data request based on application of footnote 12 would have been speculative prior to the implementation of the new TPL-001-2. From the review of the comments submitted, it does not appear that separation of the standards would be a consensus view. No change made. The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. And when such decisions do not involve any aspect of BES operation or reliability, such situations would not come under the purview of footnote 'b' as standards only apply to the BES unless stated otherwise. However, in Order 693, FERC clearly stated that it has jurisdiction over matters that do involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote 'b' solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. No change made.		

END OF REPORT

Exhibit I

Comprehensive Development Record

Project 2010-11
TPL Table 1 Order

Related Files

Status:
Adopted by the NERC Board of Trustees on February 7, 2013 and pending regulatory approval.

Purpose/Industry Need:
The SAR is to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010. The SAR provides a revision to TPL Table 1 footnote 'b' to provide clarity to industry with regard to the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. The referenced table appears in TPL-001, TPL-002, TPL-003, and TPL-004 so while the FERC Order was for TPL-002, the change is reflected in all 4 standards.

Draft	Action	Dates	Results	Consideration of Comments
TPL-001-3 (formerly TPL-001-2a) Clean **(111)** | Redline to Last Posting **(112)** Implementation Plan Clean **(113)** | Redline to Last Posting **(114)** **TPL-002-2b (formerly TPL-002-1c)** Clean **(115)** | Redline to Last Posting **(116)** Implementation Plan Clean **(117)** | Redline to Last Posting **(118)**	Recirculation Ballot Info **(119)** Vote>>	01/22/13 - 01/31/13 (closed)	Summary **(120)** Ballot Results **(121)**	
Draft 8 **TPL-001-2a** Clean **(97)** | Redline to Last Posting **(98)**	Successive Ballot Updated Info **(104)**	01/02/13 - 01/11/13 (closed)	Summary **(107)** Ballot Results **(108)**	

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Draft 7
TPL-002-1c
Clean (100)| Redline to Last Posting (101)

Implementation Plan (102)

Supporting Materials:
Unofficial Comment Form (Word) (103)</td>
<td>Info (105)

Vote>></td>
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<td>Formal Comment Period

Info (106)

Submit Comments>></td>
<td>12/10/12 - 01/11/13 (closed)</td>
<td>Comments Received (109)</td>
<td>Consideration of Comments (110)</td>
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<td rowspan="3">**Draft 7**
TPL-001-2a
Clean (81)| Redline to Last Posting (82)

Implementation Plan (83)

Draft 6
TPL-002-1c
Clean (84)| Redline to Last Posting (85)

Implementation Plan (86)

Supporting Materials:
Unofficial Comment Form (Word) (87)

Data Request Summary (88)

FERC Order 762 (89)</td>
<td>Initial Ballot

Updated Info (90)
Info (91)

Vote>></td>
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Full Record (94)</td>
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Info (92)

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TPL-001-3

Clean (71)| Redline to Last Approved (72)</td>
<td>Comment Period

Info (78)

Submit Comments>></td>
<td>07/31/12 - 08/29/12 (closed)</td>
<td>Comments Received (79)</td>
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TPL-002-1 Clean **(73)**| Redline to Last Approved **(74)** **Supporting Materials:** Unofficial Comment Form (Word) **(75)** SAR **(76)** FERC Order 762 **(77)**				
On April 19, 2012 FERC issued Order 762 remanding TPL-002-2b and FERC proposed to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.				
Implementation Plan **(55)** **TPL-001-1** Clean **(56)**| Redline to last posting **(57)** Redline to last approval **(58)** **TPL-002-1b** Clean **(59)**| Redline to last posting **(60)** Redline to last approval **(61)** **TPL-003-1a** Clean **(62)**| Redline to last posting **(63)** Redline to last approval **(64)** **TPL-004-1** Clean **(65)**| Redline to last	Recirculation Ballot Info **(68)** Vote>>	01/26/11 – 02/05/11 (closed)	Summary **(69)** Full Record **(70)**	

posting **(66)** Redline to last approval **(67)**				
Implementation Plan **(33)** **TPL-001-1** Clean **(34)** | Redline to last posting **(35)** Redline to last approval **(36)** **TPL-002-1b** Clean **(37)**| Redline to last posting **(38)** Redline to last approval **(39)** **TPL-003-1a** Clean **(40)** | Redline to last posting **(41)** Redline to last approval **(42)** **TPL-004-1** Clean **(43)**| Redline to last posting **(44)** Redline to last approval **(45)** **Supporting Materials:** Comment Form (Word) **(46)**	Initial Ballot Info **(47)** Vote>>	12/27/10 - 01/05/11 (closed)	Summary **(50)** Full Record **(51)**	Consideration of Comments **(53)**
	Ballot Pool Info **(48)**	11/19/10 - 12/22/10 (closed)		
	Comment Period Info **(49)** Submit Comments>>	11/19/10 - 01/05/11 (closed)	Comments Received **(52)**	Consideration of Comments **(54)**
Implementation Plan **(20)** TPL-001-1 Clean **(21)** | Redline to last	Comment Period Submit	09/08/10 - 10/08/10 (closed)	Comments Received **(31)**	Comment Report **(32)**

posting (22) TPL-002-1b Clean (23)| Redline to last posting (24) TPL-003-1a Clean (25)| Redline to last posting (26) TPL-004-1 Clean (27)| Redline to last posting (28) **Supporting Materials:** Comment Form (Word) (29)	Comments>> | Info (30)			
SAR (1) Implementation Plan (2) TPL-001-1 Clean (3)| Redline to last approval (4) TPL-002-1b Clean (5) | Redline to last approval (6) TPL-003-1a Clean (7) | Redline to last approval (8) TPL-004-1 Clean (9)| Redline to last approval (10) **Supporting Materials:** Comment Form (Word) (11)	Initial Ballot Vote>>| Info (12)	05/17/10 - 05/27/10 (closed)	Summary (15) Full Record (16)	Comment Report (18)
	Pre-ballot Review Join>> | Info (13)	04/15/10 - 05/17/10 (closed)		
	Comment Period Submit Comments>> | Info (14)	04/15/10 - 05/26/10 (closed)	Comments Received (17)	Comment Report (19)

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standard Authorization Request Form

Title of Proposed Standard	2010-11 TPL Table 1 Order
Request Date	April 9, 2010
Approved by SC for Posting	April 14, 2010

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)
Name John Odom	☐	New Standard
Primary Contact FRCC 1408 N. Westshore Blvd., Suite 1002 Tampa, FL 33607	X	Revision to existing Standard
Telephone 1.813.207.7985 Fax 1.813.289.5646	☐	Withdrawal of existing Standard
E-mail jodom@frcc.com	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.)

Provide clarity to industry on TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system.

Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The SAR is to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

The SAR provides a revision to TPL Table 1 footnote 'b' to provide clarity to industry with regard to the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. The referenced table appears in TPL-001, TPL-002, TPL-003, and TPL-004 so while the FERC Order was for TPL-002, the change is reflected in all 4 standards.

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

The ATFNSDT (Project 2006-02) has developed a clarification to TPL Table 1 – footnote 'b' concerning the loss of load and handling of firm transfers when a single contingency occurs on the transmission system.

With regard to the load shedding issue, the SDT is proposing the following revision to footnote 'b':

No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

On the firm transfer issue, the SDT developed the following clarification:

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

Since this clarification may present a different interpretation of footnote 'b' than the one presently used by some entities, the SDT is proposing a 60 month implementation plan to allow those entities time to react.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
X	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
X	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
x	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
TPL-001-0.1	System Performance Under Normal (No Contingency) Conditions (Category A)
TPL-002-0b	System Performance Following Loss of a Single Bulk Electric System Element (Category B)
TPL-003-0a	System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
TPL-004-0	System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Implementation Plan for Project 2010-11: TPL Table 1 Order

Standards Involved:

- TPL-001-1 — System Performance Under Normal (No Contingency) Conditions (Category A)
- TPL-002-1b — System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- TPL-003-1 — System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
- TPL-004-1 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

Prerequisite Approvals

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

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed standards and no proposed changes to other standards.

Compliance with Standards

The four standards are all applicable to both the Transmission Planner and the Planning Authority.

Effective Dates

The effective date is the date entities are expected to meet the performance identified in these standards.

The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

All other requirements remain in effect per previous approvals.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. None.

Proposed Action Plan and Description of Current Draft:

The SDT has submitted a SAR to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System by June 30, 2010. Due to the timeframe involved, the SDT has requested an Urgent Action process be approved by the Standards Committee. To accommodate this process, the SDT has supplied drafts of the affected TPL standards as part of the SAR submittal.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit SAR to SC	April 2010
2. Approval of SAR by SC	April 2010
3. 30 day pre-ballot period	April – May 2010
4. Initial ballot	May 2010
5. Recirculation ballot	June 2010
6. Submit to BOT for approval	June 2010
7. File with FERC	June 2010

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)
2. **Number:** TPL-001-1
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
   - **4.1.** Planning Authority
   - **4.2.** Transmission Planner
5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-1_R1 and TPL-001-1_ R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Compliance Monitor: Regional Reliability Organization.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame
Annually

1.3. Data Retention
None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. None.

Proposed Action Plan and Description of Current Draft:

The SDT has submitted a SAR to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System by June 30, 2010. Due to the timeframe involved, the SDT has requested an Urgent Action process be approved by the Standards Committee. To accommodate this process, the SDT has supplied drafts of the affected TPL standards as part of the SAR submittal.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit SAR to SC	April 2010
2. Approval of SAR by SC	April 2010
3. 30 day pre-ballot period	April – May 2010
4. Initial ballot	May 2010
5. Recirculation ballot	June 2010
6. Submit to BOT for approval	June 2010
7. File with FERC	June 2010

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-~~0~~1~~.1~~

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective~~May 13, 2009~~.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-~~0~~1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-~~0~~1_R1 and TPL-001-~~0~~1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-~~0~~1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1~~.~~	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) ~~Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~ No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. None.

Proposed Action Plan and Description of Current Draft:

The SDT has submitted a SAR to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System by June 30, 2010. Due to the timeframe involved, the SDT has requested an Urgent Action process be approved by the Standards Committee. To accommodate this process, the SDT has supplied drafts of the affected TPL standards as part of the SAR submittal.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit SAR to SC	April 2010
2. Approval of SAR by SC	April 2010
3. 30 day pre-ballot period	April – May 2010
4. Initial ballot	May 2010
5. Recirculation ballot	June 2010
6. Submit to BOT for approval	June 2010
7. File with FERC	June 2010

A. Introduction

1. **Title:** **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. **Number:** TPL-002-1b

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective .

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions should also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. None.

Proposed Action Plan and Description of Current Draft:

The SDT has submitted a SAR to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote ‘b’, regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System by June 30, 2010. Due to the timeframe involved, the SDT has requested an Urgent Action process be approved by the Standards Committee. To accommodate this process, the SDT has supplied drafts of the affected TPL standards as part of the SAR submittal.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit SAR to SC	April 2010
2. Approval of SAR by SC	April 2010
3. 30 day pre-ballot period	April – May 2010
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5. Recirculation ballot	June 2010
6. Submit to BOT for approval	June 2010
7. File with FERC	June 2010

A. Introduction

1. **Title:** **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. **Number:** TPL-002-~~0b~~1b

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective~~Immediately after approval of applicable regulatory authorities.~~ .

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories~~,~~, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-~~0~~1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-~~0~~1_R1 and TPL-002-~~0~~1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-~~0~~1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
~~0c~~1b	April 2010	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section - - - - - - - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) ~~Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~ No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by “study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies).” 2. “…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).” 3. “Include the effects of existing and planned protection systems, including any backup or redundant systems.” *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as “A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.”
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. None.

Proposed Action Plan and Description of Current Draft:

The SDT has submitted a SAR to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System by June 30, 2010. Due to the timeframe involved, the SDT has requested an Urgent Action process be approved by the Standards Committee. To accommodate this process, the SDT has supplied drafts of the affected TPL standards as part of the SAR submittal.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit SAR to SC	April 2010
2. Approval of SAR by SC	April 2010
3. 30 day pre-ballot period	April – May 2010
4. Initial ballot	May 2010
5. Recirculation ballot	June 2010
6. Submit to BOT for approval	June 2010
7. File with FERC	June 2010

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-1a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective .

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-1_R1 and TPL-003-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
1a	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	 Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c]	 No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	 Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c]	 No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	 No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. None.

Proposed Action Plan and Description of Current Draft:

The SDT has submitted a SAR to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System by June 30, 2010. Due to the timeframe involved, the SDT has requested an Urgent Action process be approved by the Standards Committee. To accommodate this process, the SDT has supplied drafts of the affected TPL standards as part of the SAR submittal.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit SAR to SC	April 2010
2. Approval of SAR by SC	April 2010
3. 30 day pre-ballot period	April – May 2010
4. Initial ballot	May 2010
5. Recirculation ballot	June 2010
6. Submit to BOT for approval	June 2010
7. File with FERC	June 2010

A. Introduction

1. Title: **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. Number: TPL-003-~~0a~~1a

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective~~April 1, 2005~~.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-~~0~~1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-~~0~~1_R1 and TPL-003-~~0~~1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-~~0~~1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item "e" on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
~~0b~~1a	~~April 2010~~TBD	Revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) ~~Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~ No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

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MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. None.

Proposed Action Plan and Description of Current Draft:

The SDT has submitted a SAR to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote ‘b’, regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System by June 30, 2010. Due to the timeframe involved, the SDT has requested an Urgent Action process be approved by the Standards Committee. To accommodate this process, the SDT has supplied drafts of the affected TPL standards as part of the SAR submittal.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit SAR to SC	April 2010
2. Approval of SAR by SC	April 2010
3. 30 day pre-ballot period	April – May 2010
4. Initial ballot	May 2010
5. Recirculation ballot	June 2010
6. Submit to BOT for approval	June 2010
7. File with FERC	June 2010

A. Introduction

1. Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. Number: TPL-004-1

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. None.

Proposed Action Plan and Description of Current Draft:

The SDT has submitted a SAR to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System by June 30, 2010. Due to the timeframe involved, the SDT has requested an Urgent Action process be approved by the Standards Committee. To accommodate this process, the SDT has supplied drafts of the affected TPL standards as part of the SAR submittal.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit SAR to SC	April 2010
2. Approval of SAR by SC	April 2010
3. 30 day pre-ballot period	April – May 2010
4. Initial ballot	May 2010
5. Recirculation ballot	June 2010
6. Submit to BOT for approval	June 2010
7. File with FERC	June 2010

A. Introduction

1. Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. Number: TPL-004-~~0a~~ 1

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective~~April 1, 2005~~

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority’s and Transmission Planner’s assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-~~0~~1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-~~0~~1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) ~~Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~ No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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Unofficial Comment Form for SAR for Project 2010-11: TPL Table 1 Order

Please **DO NOT** use this form to submit comments. Please the electronic form located at the link below to submit comments on the SAR for Project 2010-11: TPL Table 1 Order. This comment form must be completed by **May 25, 2010.**

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information

The SAR is to address FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010.

The SAR provides a revision to TPL Table 1 footnote 'b' to provide clarity to industry with regard to the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. The referenced table appears in TPL-001, TPL-002, TPL-003, and TPL-004 so while the FERC Order was for TPL-002, the change is reflected in all 4 standards.

1. The SDT is proposing a revision to footnote 'b' in the TPL tables to comply with FERC Order RM-06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.

   ☐ Yes
   ☐ No
   Comments:

2. Are you aware of any conflicts caused by compliance with the proposed language in Table 1 — footnote b and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement? If yes, please identify the conflict.

   ☐ Yes
   ☐ No
   Comments:

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Standards Announcement

Initial Ballot Window Open
May 17–27, 2010

Now available at: https://standards.nerc.net/CurrentBallots.aspx

TPL Table 1, Footnote B (Project 2010-11)

An initial ballot window for the TPL Table 1, Footnote B changes is now open **until 8 p.m. EST on May 27, 2010**.

The ballot includes four draft standards and an implementation plan. The only change proposed in each of the four standards (TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1) is to Table 1, Footnote 'b'.

Instructions

Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Next Steps

Voting results will be posted and announced after the ballot window closes.

Project Background

The Assess Transmission Future Needs Standard Drafting Team (Project 2006-02) has developed a clarification to TPL Table 1 — footnote 'b' concerning the loss of load and handling of firm transfers when a single contingency occurs on the transmission system.

The drafting team is proposing the following revision to footnote 'b': No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

On the firm transfer issue, the drafting team developed the following clarification:

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

Since this clarification may present a different interpretation of footnote 'b' than the one presently used by some entities, the SDT is proposing a 60 month implementation plan to allow those entities time to react

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Lauren Koller at Lauren.Koller@nerc.net

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Standards Announcement

Standards Authorization Request (SAR)
Ballot Pool and Pre-ballot Window (with Comment Period)
Project 2010-11: TPL Table 1, Footnote B

Now available at: http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

TPL Table 1, Footnote B SAR (Project 2010-11)

The Standards Committee, in response to a FERC Order issued March 18, 2010, has posted a proposed SAR, four draft standards, TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1, and an implementation plan, for a simultaneous pre-ballot review and 40-day comment period. The only change proposed in each of the four standards is to Table 1, Footnote 'b'.

The Order requires the ERO to file the revised standards by June 30. 2010. To meet this due date, the Standards Committee approved the following deviation from the standards development process:

- The proposed changes to the standards will be posted for a 40-day comment period. The Ballot Pool will be formed during the first 30 days of the 40-day comment period;
- The initial ballot will be conducted during the last 10 days of the 40-day comment period; and
- The drafting team may make modifications to the footnote between the initial and recirculation ballots based on stakeholder comments to improve the overall quality of the footnote.

Ballot Pool (through May 17, 2010)

Registered Ballot Body members may join the ballot pool to be eligible to vote on this interpretation **until 8 a.m. EDT on May 17, 2010**.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2010-11_TPL_SAR_in

Comment Period (through May 25, 2010)

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at 609-524-7047.

The status, purpose, a clean and redline version of the four standards, and supporting documents for this project — including an off-line, unofficial copy of the questions listed in the comment form — are posted at the following site: http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Project Background:

The Assess Transmission Future Needs Standard Drafting Team (Project 2006-02) has developed a clarification to TPL Table 1 — footnote 'b' concerning the loss of load and handling of firm transfers when a single contingency occurs on the transmission system.

The drafting team is proposing the following revision to footnote 'b': No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

On the firm transfer issue, the drafting team developed the following clarification:

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

Since this clarification may present a different interpretation of footnote 'b' than the one presently used by some entities, the SDT is proposing a 60 month implementation plan to allow those entities time to react.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
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Standards Announcement

Standards Authorization Request (SAR)
Ballot Pool and Pre-ballot Window (with Comment Period)
Project 2010-11: TPL Table 1, Footnote B

Now available at: http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

TPL Table 1, Footnote B SAR (Project 2010-11)

The Standards Committee, in response to a FERC Order issued March 18, 2010, has posted a proposed SAR, four draft standards, TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1, and an implementation plan, for a simultaneous pre-ballot review and 40-day comment period. The only change proposed in each of the four standards is to Table 1, Footnote 'b'.

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During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2010-11_TPL_SAR_in

Comment Period (through May 25, 2010)

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at 609-524-7047.

The status, purpose, a clean and redline version of the four standards, and supporting documents for this project — including an off-line, unofficial copy of the questions listed in the comment form — are posted at the following site: http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Project Background:

The Assess Transmission Future Needs Standard Drafting Team (Project 2006-02) has developed a clarification to TPL Table 1 — footnote 'b' concerning the loss of load and handling of firm transfers when a single contingency occurs on the transmission system.

The drafting team is proposing the following revision to footnote 'b': No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

On the firm transfer issue, the drafting team developed the following clarification:

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

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For more information or assistance,
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Standards Announcement
Initial Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

TPL Table 1, Footnote B (Project 2010-11)
The initial ballot for TPL Table 1, Footnote B ended on May 27, 2010.

Ballot Results
Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 84.41 %
Approval: 63.75 %

Since at least one negative ballot included a comment, these results are not final. A second (or recirculation) ballot must be conducted. Ballot criteria are listed at the end of the announcement.

Next Steps
As part of the recirculation ballot process, the drafting team must draft and post responses to voter comments. The drafting team will also determine whether or not to make revisions to the balloted item(s). Should the team decide to make revisions, the revised item(s) will return to the initial ballot phase.

Project Background
The Assess Transmission Future Needs Standard Drafting Team (Project 2006-02) has developed a clarification to TPL Table 1 — footnote 'b' concerning the loss of load and handling of firm transfers when a single contingency occurs on the transmission system.

The drafting team is proposing the following revision to footnote 'b': No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.

On the firm transfer issue, the drafting team developed the following clarification:

No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

Since this clarification may present a different interpretation of footnote 'b' than the one presently used by some entities, the SDT is proposing a 60 month implementation plan to allow those entities time to react

More information is available on the project page: http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Criteria

Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention, and (2) A two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses. If there are no negative votes with reasons from the first ballot, the results of the first ballot shall stand. If, however, one or more members submit negative votes with reasons, a second ballot shall be conducted.

For more information or assistance,
please contact Lauren Koller at Lauren.Koller@nerc.net

Ballot Results	
Ballot Name:	Project 2010-11 SAR for TPL Table 1 Order_in
Ballot Period:	5/17/2010 - 5/27/2010
Ballot Type:	Initial
Total # Votes:	222
Total Ballot Pool:	263
Quorum:	84.41 % The Quorum has been reached
Weighted Segment Vote:	63.75 %
Ballot Results:	The standard will proceed to recirculation ballot.

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	77	1	36	0.59	25	0.41	1	15
2 - Segment 2.	10	0.7	5	0.5	2	0.2	1	2
3 - Segment 3.	58	1	30	0.566	23	0.434	2	3
4 - Segment 4.	13	1	7	0.636	4	0.364	1	1
5 - Segment 5.	49	1	25	0.641	14	0.359	0	10
6 - Segment 6.	36	1	17	0.63	10	0.37	3	6
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.3	2	0.2	1	0.1	1	3
9 - Segment 9.	5	0.3	1	0.1	2	0.2	1	1
10 - Segment 10.	8	0.7	6	0.6	1	0.1	1	0
Totals	**263**	**7**	**129**	**4.463**	**82**	**2.537**	**11**	**41**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Negative	View
1	Ameren Services	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver	Affirmative	View
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Avista Corp.	Scott Kinney		
1	BC Transmission Corporation	Gordon Rawlings	Negative	View
1	Beaches Energy Services	Joseph S. Stonecipher	Affirmative	

1	Black Hills Corp	Eric Egge	Negative	View
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy	Paul Rocha	Abstain	
1	Central Maine Power Company	Brian Conroy		
1	City of Vero Beach	Randall McCamish	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek		
1	Commonwealth Edison Co.	Daniel Brotzman	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	View
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker	Negative	View
1	Dominion Virginia Power	John K Loftis	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	E.ON U.S. LLC	Larry Monday		
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	View
1	GDS Associates, Inc.	Claudiu Cadar	Negative	View
1	Georgia Transmission Corporation	Harold Taylor, II	Negative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Negative	View
1	Idaho Power Company	Ronald D. Schellberg	Negative	View
1	ITC Transmission	Elizabeth Howell		
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stan T. Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	View
1	Lee County Electric Cooperative	John W Delucca	Negative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	National Grid	Saurabh Saksena		
1	New York Power Authority	Arnold J. Schuff		
1	Northeast Utilities	David H. Boguslawski	Affirmative	View
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oncor Electric Delivery	Michael T. Quinn	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	View
1	Otter Tail Power Company	Lawrence R. Larson	Negative	View
1	Pacific Gas and Electric Company	Chifong L. Thomas	Negative	View
1	PacifiCorp	Mark Sampson	Negative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	
1	Potomac Electric Power Co.	Richard J Kafka	Affirmative	View
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Negative	View
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch	Affirmative	
1	San Diego Gas & Electric	Linda Brown	Affirmative	View
1	Santee Cooper	Terry L. Blackwell	Negative	View
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Negative	View
1	Southern Company Services, Inc.	Horace Stephen Williamson	Negative	View
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Negative	View
1	Southwestern Power Administration	Gary W Cox		
1	Tennessee Valley Authority	Larry Akens	Affirmative	View
1	Tri-State G & T Association Inc.	Keith V. Carman	Negative	View
1	Tucson Electric Power Co.	John Tolo	Negative	View

1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Brandy A Dunn		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Transmission Corporation	Faramarz Amjadi	Negative	View
2	California ISO	Timothy VanBlaricom	Negative	View
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	View
2	ISO New England, Inc.	Kathleen Goodman	Abstain	
2	Midwest ISO, Inc.	Jason L Marshall	Affirmative	
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Affirmative	
3	Alabama Power Company	Richard J. Mandes	Negative	View
3	Allegheny Power	Bob Reeping	Negative	
3	Ameren Services	Mark Peters	Affirmative	
3	American Electric Power	Raj Rana	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Power Agency	Duane S. Dahlquist	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	View
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	Cleco Utility Group	Bryan Y Harper	Abstain	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	David A. Lapinski	Negative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	View
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	W. R. Schoneck	Affirmative	View
3	Florida Power Corporation	Lee Schuster	Negative	View
3	Georgia Power Company	Anthony L Wilson	Negative	View
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Negative	
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Gwen S Frazier	Negative	View
3	Hydro One Networks, Inc.	Michael D. Penstone	Negative	View
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Negative	View
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Don Horsley	Negative	View
3	New York Power Authority	Marilyn Brown	Negative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	OTP Wholesale Marketing	Bradley Tollerson	Negative	
3	PacifiCorp	John Apperson	Negative	View
3	PECO Energy an Exelon Co.	Vincent J. Catania	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Negative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	Zack Dusenbury	Negative	View
3	Seattle City Light	Dana Wheelock	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young	Negative	View

3	Southern California Edison Co.	David Schiada	Negative	View
3	Tampa Electric Co.	Ronald L Donahey		
3	Wisconsin Electric Power Marketing	James R. Keller	Negative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Affirmative	View
4	Consumers Energy	David Frank Ronk	Negative	View
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	View
4	Georgia System Operations Corporation	Guy Andrews	Negative	
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Modesto Irrigation District	Spencer Tacke	Negative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Avista Corp.	Edward F. Groce		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	View
5	City of Tallahassee	Alan Gale	Affirmative	View
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Affirmative	
5	Cleco Power LLC	Grant Bryant		
5	Conectiv Energy Supply, Inc.	Kara Dundas		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy	James B Lewis	Negative	View
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Robert Smith	Negative	
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Affirmative	View
5	Great River Energy	Cynthia E Sulzer	Negative	
5	JEA	Donald Gilbert	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Negative	View
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	
5	New York Power Authority	Gerald Mannarino	Negative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	Otter Tail Power Company	Ward Uggerud	Negative	
5	PacifiCorp	Sandra L. Shaffer	Negative	
5	Portland General Electric Co.	Gary L Tingley		
5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	PSEG Power LLC	David Murray	Affirmative	
5	RRI Energy	Thomas J. Bradish	Negative	View
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South California Edison Company	Ahmad Sanati	Negative	View
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	George T. Ballew	Affirmative	View
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Negative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		

5	Xcel Energy, Inc.	Liam Noailles	Negative	View
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Black Hills Corp	Tyson Taylor		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	View
6	Cleco Power LLC	Matthew D Cripps	Abstain	
6	Colorado Springs Utilities	John Mick	Negative	View
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Great River Energy	Donna Stephenson	Negative	
6	Kansas City Power & Light Co.	Thomas Saitta	Negative	View
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Negative	View
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Negative	
6	OTP Wholesale Marketing	Bruce Glorvigen	Abstain	
6	Progress Energy	James Eckelkamp		
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Negative	View
6	RRI Energy	Trent Carlson	Negative	View
6	Santee Cooper	Suzanne Ritter	Negative	View
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	View
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		James A Maenner	Negative	
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Abstain	
8	Montana Consumer Counsel	Lawrence P Nordell		
8	Power Energy Group LLC	Peggy Abbadini		
8	Shafer, Kline, & Warren Inc. (SKW)	Michael J Bequette, P.E.	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	California Energy Commission	William Mitchell Chamberlain	Negative	View
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson		
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	North Carolina Utilities Commission	Kimberly J. Jones	Negative	View
9	Oregon Public Utility Commission	Jerome Murray	Abstain	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R. Schoenecker	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith	Affirmative	View
10	SERC Reliability Corporation	Carter B Edge	Affirmative	View
10	Western Electricity Coordinating Council	Louise McCarren	Negative	View

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Account Log-In/Register

Individual or group. (22 Responses)
Name (13 Responses)
Organization (13 Responses)
Question 1 (22 Responses)
Question 1 Comments (22 Responses)
Question 2 (22 Responses)
Question 2 Comments (22 Responses)

-
Group
No
The proposed changes do not adequately address FERC's concerns in RM06-16-009. The Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." The proposed changes to footnote 'b' indicate "No interruption of firm Load is allowed except:… (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities." The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as "the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency." In referencing Order 693, the Commission reiterated its position that TPL standards "should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." "Must" should be used instead of "should" in the last sentence of the footnote, making it to read "Facility Ratings in those regions must also be respected."
Yes
Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.
Individual
Robert Casey
Georgia Transmission Corporation (Bulk System Planning)
No
Georgia Transmission Corporation (GTC) believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We believe that FERC's directive in (Docket No. RM06-16) to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. We also note that on April 19 NERC filed a request for rehearing with FERC asking that the Commission revise the directive in Paragraph 8 of the March 18 TPL-002 Order to allow NERC the necessary time to incorporate changes to the TPL-002 Reliability Standard through the Reliability Standards Development Process that are necessary to achieve bulk power system reliability. NERC also requested that the Commission grant NERC's Motion for Stay to stay the Order so that a public technical conference with opportunity for comment can be held in order to provide parties an opportunity to meet and discuss the technical considerations of developing a modification to the TPL-002 standard that prohibits the loss of non-consequential firm load in the event of an N-1 contingency. NERC's April 19 filing pointed out that if the Commission's directive to disallow the loss of non-consequential firm load for an N-

1 contingency is implemented, a question is presented regarding whether the Reliability Standard still serves the purpose of ensuring the Reliable Operation of the bulk power system by preventing instability, uncontrolled separation, and cascading failures. That is, the Commission's directive sets forth an expectation that NERC is to implement standards that address all loss of load at costs that may not be commensurate with bulk power system reliability, as statutorily defined, which is fundamentally different from what the Reliability Standards were intended to do.
Yes
See response to Question #1.
Group
Yes
For better clarity delete the phrase "when coupled with" in the second paragraph of footnote 'b.'
No
The comments expressed herein represent a consensus of the views of the above named members of the SERC Engineering Committee Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.
Group
Yes
No
Individual
Thad Ness
American Electric Power
Yes
No
Individual
Kasia Mihalchuk
Manitoba Hydro
Yes
MH agrees with the SDT proposal.
No
Group
No
We propose that the section in double parentheses be deleted. The proposed wording by the drafting team seems to imply that the curtailment of firm transmission service is permitted to address single contingency constraints if coupled with the redispatch of network resources. The original language stated only that curtailments were permitted to prepare for the next contingency, not to address loading related to the initial contingency. The proposed wording could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint. Southern Companies recommend that the original language relating to "preparing for the next contingency" be incorporated into the drafting team's proposal. ((Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.)) No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch. where it can It must be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.
No
Individual

Martin Bauer
US Bureau of Reclamation
Yes
No
Group
Yes
On the firm transfer issues, the term "Firm Transmission Service" should be replaced with "Firm Transfers" to be consistent with the fourth column of the existing Table 1 Transmission System Standards - Normal and Emergency Conditions.
No
Individual
Kirit Shah
Ameren
Yes
We were ok with the previous language. Though we do not intend to drop non-consequential load for a single contingency, we undersatnd that other ares may have been following such practice without degarding the relaibility of BES. We believe that they can continue this practice if they develop non-firm contracts with these customers.
No
Group
No
For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
No
Individual
Robert W. Roddy
Dairyland Power Cooperative
No
DPC concurs with the MRO comments: For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
No
Individual
Marty Berland
Progress Energy
No
Progress Energy applauds NERC's efforts to improve the footnote (b) language with respect to conditional allowance of curtailing Firm Transmission Service, which is addressed in the second paragraph of the proposed new footnote (b). PE remains concerned, however, that the first paragraph of the proposed new footnote (b) does not allow for curtailment of non-radial non-consequential load. The ability to curtail non-consequential load in the planning horizon can be a useful tool to mitigate local area issues, and has not been detrimental to the Bulk Electric System (BES). Disallowing the curtailment of non-radial non-consequential load essentially prohibits taking action in situations in which the load in question is clearly at a localized self-contained level of the system, i.e. the distribution system(s) served by the Transmission Owner/Operator. Prohibiting the curtailment of local load thus constitutes regulating distribution feeder reliability rather than BES reliability. Events that could be mitigated through the curtailment of local, non-radial non-consequential load are infrequent, and such curtailment has no material effect on the reliability of the BES. PE therefore suggests that the following addition (item (3)) to the first paragraph of the proposed footnote (b) be considered: "No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, and/or (2) Planned or controlled interruption of

Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities, and/or (3) Planned or controlled interruption of any additional Load required to mitigate the post-contingency results, provided that the non-consequential load being shed for the event is localized, and provided that the total load shed for the event does not exceed 2% of the Planned system peak demand or 200 MW, whichever value is less.”
Yes
There is the potential for conflict between Table 1 – Footnote (b) as currently proposed, which can be considered to regulate local distribution reliability without improving BES reliability, and local service reliability issues which are under the purview of state regulatory agencies. For example, the North Carolina Utilities Commission (NCUC) commented regarding this concern in the ballot which ended March 1 in Project 2006-02. Specifically, NCUC commented that they were “…concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1 is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions…” Progress Energy believes that NCUC’s concerns are legitimate. BES reliability should address the avoidance and mitigation of cascading outages and BES facility damage, rather than limited, controlled local area loss of load, in order to avoid this conflict and overlap of regulation.
Group
Yes
Yes
This is not an issue for historic PJM members, but as PJM has expanded and as a result of the merger of historic councils into RFC, I am aware that not all regions had standards equal to those of MAAC, and this has been an issue worked out between transmission planners (historic transmission owners) and their local regulators. It is ultimately a cost issue for loss of local load that does not affect the overall reliability of the interconnected BES.
Individual
Michael R. Lombardi
Northeast Utilities
Yes
Yes
Northeast Utilities (NU) believes the language of the proposed revision to footnote ‘b’ can be better defined as the proposed revision is subject to interpretation by the different entities and regulatory agencies. Future conflicts can be minimized by further clarifying the proposed revision. Also, NU is concerned that this new modification does not specify the amount of permissible load shed nor does it require the planning entity to minimize load shedding under this exception.
Individual
Charles Lawrence
American Transmission Company
No
For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
No
Group
Yes
Yes
It should be noted that conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC’s position on non-consequential load loss. In RM-06-16-009, the Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is “based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios.” In the US, State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position. Similar conflicts may also exist in Canada.
Individual

Greg Rowland
Duke Energy
No
Duke Energy voted "Negative" on the initial and current ballots of TPL-001-1, primarily because Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We also sought rehearing on the Commission's March 18 Order Setting Deadline for Compliance (Docket No. RM06-16), with respect to this and other issues. We believe that FERC's directive in that Order to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the potential impacts (environmental, historical, archaeological, aesthetic…) of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. Duke offers the following ideas on alternatives for the SDT to consider that will allow for appropriate discretion and facilitate proper planning while allowing non-consequential load loss (NCLL). The standard should allow for dropping of limited amounts of non-consequential load in situations where it would be reasonable for a bounded time period and under restricted system conditions (e.g. 1-3 years only when load is >90 % of peak conditions). Dropping of non-consequential load would be prudent planning in situations where the near term impact of load projections or implementation of nearby transmission/generation projects will alleviate the necessity of an upgrade to meet N-1 conditions. Also, reliability of service to end-use customer is impacted by the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customers' level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to avoid projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics (e.g. SAIFI/SAIDI/ASAI) should also be considered by the SDT for determination of acceptable use of NCLL.
Yes
See response to question #1.
Individual
Bill Middaugh
Tri-State Generation and Transmission Association, Inc.
No
Tri-State does believe that the new footnote is an improvement, but thinks there are still some changes necessary. We believe that the word "only" should be removed from the phrase "…where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities" because that discrimination was not required in FERC Order RM-06-16-009. There may be times when facilities near the temporary radial facilities might also fall outside the limits set in reliability criteria but the situation is mitigated if the load shedding occurs at the radial facility. The meaning of the second paragraph of the new footnote is unclear. Tri-State recommends changing it to "Curtailment of Firm Transmission Service is not allowed unless it is coupled with curtailment-offsetting resources that are obligated to re-dispatch. Further, the curtailment activities cannot result in the shedding of any Firm load or in violations of Facility Ratings, either internal or external to the planning region."
Yes
We believe that FERC's directive in FERC Order RM-06-16-009 to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load.
Group
Yes

Yes
This is an area of fuzziness between State jurisdiction and Federal jurisdiction. In all honesty, shedding load for local area impacts has nothing to do with BES reliability and should not be under FERC jurisdiction under Section 215 of the Federal Power Act, but rather State jurisdiction for quality of service issues. However, there is also the matter of FERC jurisdiction over commercial matters and the opportunity to “game” the original footnote by transmission providers by allowing firm load shedding to grant firm transmission service for themselves, thereby avoiding or deferring transmission investment, while at the same time denying or requiring others to build the same transmission avoided in order to obtain transmission service. We can see how difficult it is from a drafting team’s perspective in achieving a balanced position between these different matters. The drafting team should be applauded for finding a reasonable position.
Individual
Roger Champagne
Hydro-Québec TransÉnergie (HQT)
No
The proposed changes do not adequately address FERC’s concerns in RM06-16-009. The Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is “based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios.” The proposed changes to footnote ‘b’ indicate “No interruption of firm Load is allowed except:… (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.” The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as “the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency.” In referencing Order 693, the Commission reiterated its position that TPL standards “should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency.” “Must” should be used instead of “should” in the last sentence of the footnote, making it to read “Facility Ratings in those regions must also be respected.”
Yes
Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC’s position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.
Individual
Dan Rochester
Independent Electricity System Operator
Yes
IESO supports the revisions made to footnote ‘b’ based on the present definitions of BES and Firm Demand and on the understanding that the NERC standards apply only to the BES as defined in the NERC Glossary as follows: “As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.” To be clear, our interpretation of the present definition of BES is that it defers to each Regional Reliability Organization to define the elements of the power system that are considered BES and, therefore in the NPCC Region, "BES as defined by NERC" = "BPS as defined by NPCC".
No

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Project 2010-11: TPL Table 1 Order and Comments Submitted with Initial Ballots

The Standards Committee thanks all commenters who submitted comments on the proposed SAR for the TPL Table 1 Order. The SAR proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

The SAR, implementation plan, and the clean and redline versions to the four TPL standards were posted for a 40-day public comment period from April 15, 2010 through May 27, 2010. Stakeholders were asked to provide feedback on the standards through a special electronic comment form. There were 22 sets of comments, including comments from more than 80 different people from approximately 40 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

The initial ballot for the proposed changes to the four TPL standards was conducted from May 17-27, 2010. The comments submitted with initial ballots and the drafting team's responses to those comments are contained in this report.

All comments submitted during the comment period and the initial ballot results are posted on the following page:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Based on stakeholder comments, the drafting team has made some additional changes to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT from the cited inputs that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when load could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand is appropriate in certain limited circumstances and that such usage is not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand were not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that requires ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in the 2nd posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

The above changes will be noted to stakeholders in a separate posting before the initiation of another ballot.

The revised Footnote 'b' is:

b) An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- Demand that is directly served by the elements that are removed from service as a result of the Contingency
- Interruptible Demand or Demand-Side Management
- Demand that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

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

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

Comments and Responses from Formal Comment Period:

Comments and Responses from Initial Ballot:

The Industry Segments are:

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

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
4.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
5.	Sylvain Clermont	Hydro-Quebec TransEnergie		1
6.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
7.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
8.	Ben Eng	New York Power Authority	NPCC	4
9.	Brian Evans-Mongeon	Utility Services	NPCC	8
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

		Commenter	Organization	Industry Segment 1	2	3	4	5	6	7	8	9	10
15.	Randy MacDonald		New Brunswick System Operator	NPCC					2				
16.	Bruce Metruck		New York Power Authority	NPCC					6				
17.	Lee Pedowicz		Northeast Power Coordinating Council	NPCC					10				
18.	Robert Pellegrini		The United Illuminating Company	NPCC					1				
19.	Saurabh Saksena		National Grid	NPCC					1				
20.	Michael Schiavone		National Grid	NPCC					1				
2.	Group	Philip R. Kleckley	South Carolina Electric & Gas	X		X		X					
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Bob Jones		Southern Company Services - Trans.	SERC					1				
2.	David Marler		Tennessee Valley Authority	SERC					1				
3.	Charles Long		Entergy	SERC					1				
4.	James Manning		North Carolina Electric Membership Corporation	SERC					3				
5.	Pat Huntley		SERC Reliability Corporation	SERC					10				
3.	Group	John Bee	Exelon Transmission Strategy & Compliance	X		X		X					
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Mortenson, Eric		:(ComEd)	RFC					1				
2.	Weaver, David W		(PECO)	RFC					1				
3.	McHugh, Kathleen P		(PECO)	RFC					1				
4.	Kay, Thomas W		(ComEd)	RFC					1				
5.	Szymczak, Ronald		(ComEd)	RFC					1				
6.	Chu, Ron F		(PECO)	RFC					1				
7.	Donnelly, Michael J		(PECO)	RFC					1				
8.	Kliros, Chris B		(ComEd)	RFC					1				
9.	Mills, Paul M		(ComEd)	RFC					1				
10.	Webb, Becky		(ComEd)	RFC					1				
4.	Group	Denise Koehn	BPA, Transmission Reliability Program	X		X		X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Chuck Matthews		BPA, Transmission Planning	WECC					1				
2.	Berhanu Tesema		BPA, Transmission Planning	WECC					1				
3.	Larry Furumasu		BPA, Transmission Planning	WECC					1				
4.	Kyle Kohne		BPA, Transmission Planning	WECC					1				
5.	Don Watkins		BPA, Transmission System Operations	WECC					1				
6.	Rebecca Berdahl		BPA, Power, Long Term Sales and Purchases	WECC					3				
5.	Group	Carol Gerou	Midwest Reliability Organization										X
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Chuck Lawrence		American Transmission Company	MRO					1				
2.	Tom Webb		Wisconsin Public Service	MRO					3, 4, 5, 6				
3.	Terry Bilke		Midwest ISO Inc.	MRO					2				
4.	Jodi Jenson		Western Area Power Administration	MRO					1, 6				
5.	Ken Goldsmith		Alliant Energy	MRO					4				
6.	Dave Rudolph		Basin Electric Power Cooperative	MRO					1, 3, 5, 6				
7.	Eric Ruskamp		Lincoln Electric System	MRO					1, 3, 5, 6				
8.	Joseph Knight		Great River Energy	MRO					1, 3, 5, 6				
9.	Joe DePoorter		Madison Gas & Electric	MRO					3, 4, 5, 6				
10.	Scott Nickels		Rochester Public Utilities	MRO					4				
11.	Terry Harbour		MidAmerican Energy Company	MRO					1, 3, 5, 6				
6.	Group	Richard Kafka	Pepco Holdings, Inc.	X		X		X	X				
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Jim Summers		Delmarva Power and Light Co.	RFC					1				
2.	John Radman		Potomac Electric Power Company	RFC					1				
7.	Group	Ben Li	IESO		X								
	Additional Member		Additional Organization	Region					Segment Selection				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1. Bill Phillips			MISO	MRO									
2. James Castle			NYISO	NPCC									
3. Charles Yeung			SPP	SPP									
4. Lourdes Estrada-Salinero			CAISO	WECC									
5. Patrick Brown			PJM	RFC									
6. Steve Myers			ERCOT	ERCOT									
8.	Group	Frank Gaffney	Florida Municipal Power Agency	X			X	X	X				
Additional Member			Additional Organization	Region					Segment Selection				
1. Timothy Beyrle			Utilities Commission of New Smyrna Beach	FRCC					4				
2. Greg Woessner			Kissimmee Utility Authority	FRCC					1				
3. Jim Howard			Lakeland Electric	FRCC					1				
4. Lynne Mila			City of Clewiston	FRCC					3				
5. Joe Stonecipher			Beaches Energy Services	FRCC					1				
6. Cairo Vanegas			Fort Pierce Utility Authority	FRCC					4				
9.	Individual	Stephen Mizelle	Southern Company Transmission	X									
10.	Individual	Robert Casey	Georgia Transmission Corporation (Bulk System Planning)	X									
11.	Individual	Thad Ness	American Electric Power	X		X		X	X				
12.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
13.	Individual	Martin Bauer	US Bureau of Reclamation					X					
14.	Individual	Kirit Shah	Ameren	X		X		X	X				
15.	Individual	Robert W. Roddy	Dairyland Power Cooperative	X		X		X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
16.	Individual	Marty Berland	Progress Energy	X		X		X	X				
17.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
18.	Individual	Charles Lawrence	American Transmission Company	X									
19.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
20.	Individual	Bill Middaugh	Tri-State Generation and Transmission Association, Inc.	X		X		X	X				
21.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
22.	Individual	Dan Rochester	Independent Electricity System Operator		X								

1. The SDT is proposing a revision to footnote ‘b’ in the TPL tables to comply with FERC Order RM-06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote ‘b’, regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.

Summary Consideration: The SDT has listened to the comments from the industry, understands the concerns raised, and has made changes to the footnote to balance the various industry concerns while assuring BES reliability.

Stakeholders identified that the terminology used in Footnote ‘b’ didn’t match the terminology used in the associated column heading of Table 1 – ‘Loss of Demand or Curtailed Firm Transfers.’ For additional clarity, the team made the following terminology changes:

- The term ‘Load’ was replaced with ‘Demand’
- The term ‘Firm Transmission Service’ was replaced with ‘firm transfers’

While the initial ballot results came close to the required approval percentage, it was clear to the SDT from the cited inputs that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when load could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn’t been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in this 2nd posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote 'b' to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial~~

~~Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Duke Energy	No	Duke Energy voted "Negative" on the initial and current ballots of TPL-001-1, primarily because Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We also sought rehearing on the Commission's March 18 Order Setting Deadline for Compliance (Docket No. RM06-16), with respect to this and other issues. We believe that FERC's directive in that Order to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the potential impacts (environmental, historical, archaeological, aesthetic...) of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. Duke offers the following ideas on alternatives for the SDT to consider that will allow for appropriate discretion and facilitate proper planning while allowing non-consequential load loss (NCLL).The standard should allow for dropping of limited amounts of non-consequential load in situations where it would be reasonable for a

Organization	Yes or No	Question 1 Comment
		bounded time period and under restricted system conditions (e.g. 1-3 years only when load is >90 % of peak conditions). Dropping of non-consequential load would be prudent planning in situations where the near term impact of load projections or implementation of nearby transmission/generation projects will alleviate the necessity of an upgrade to meet N-1 conditions. Also, reliability of service to end-use customer is impacted by the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customers' level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to avoid projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics (e.g. SAIFI/SAIDI/ASAI) should also be considered by the SDT for determination of acceptable use of NCLL.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Midwest Reliability Organization	No	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by

Organization	Yes or No	Question 1 Comment
		the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
Dairyland Power Cooperative	No	DPC concurs with the MRO comments: For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
American Transmission Company	No	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.

Response: The SDT has added the second bullet to address your concern.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements.   When interruption of Demand is utilized within the planning process, such interruption is limited to:

- o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- o Interruptible Demand or Demand-Side Management
- o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Georgia Transmission Corporation (Bulk System Planning)	No	Georgia Transmission Corporation (GTC) believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We believe that FERC's directive in (Docket No. RM06-16) to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. We also note that on April 19 NERC filed a request for rehearing with FERC asking that the Commission revise the directive in Paragraph 8 of the March 18 TPL-002 Order to allow NERC the necessary time to incorporate changes to the TPL-002 Reliability Standard through the Reliability Standards Development Process that are necessary to achieve bulk power system reliability. NERC also requested that the Commission grant NERC's Motion for Stay to stay the Order so that a public technical conference with opportunity for comment can be held in order to provide parties an opportunity to meet and discuss the technical considerations of developing a modification to the TPL-002 standard that prohibits the loss of non-consequential firm load in the event of an N-1 contingency. NERC's April 19 filing pointed out that if the Commission's directive to disallow the loss of non-consequential firm load for an N-1 contingency is implemented, a question is presented regarding whether the Reliability Standard still serves the purpose of ensuring the Reliable Operation of the bulk power system by preventing instability, uncontrolled separation, and cascading failures. That is, the Commission's directive sets forth an expectation that NERC is to implement standards that address all loss of load at costs that may not be commensurate with bulk power system reliability, as statutorily defined, which is fundamentally different from what the Reliability Standards were intended to do.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the

Organization	Yes or No	Question 1 Comment
various industry concerns while assuring BES reliability. . Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Progress Energy	No	Progress Energy applauds NERC's efforts to improve the footnote (b) language with respect to conditional allowance of curtailing Firm Transmission Service, which is addressed in the second paragraph of the proposed new footnote (b). PE remains concerned, however, that the first paragraph of the proposed new footnote (b) does not allow for curtailment of non-radial non-consequential load. The ability to curtail non-consequential load in the planning horizon can be a useful tool to mitigate local area issues, and has not been detrimental to the Bulk Electric System (BES). Disallowing the curtailment of non-radial non-consequential load essentially prohibits taking action in situations in which the load in question is clearly at a localized self-contained level of the system, i.e. the distribution system(s) served by the Transmission Owner/Operator. Prohibiting the curtailment of local load thus constitutes regulating distribution feeder reliability rather than BES reliability. Events that could be mitigated through the curtailment of local, non-radial non-consequential load are infrequent, and such curtailment has no material effect on the reliability of the BES.

Organization	Yes or No	Question 1 Comment
		PE therefore suggests that the following addition (item (3)) to the first paragraph of the proposed footnote (b) be considered:"No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, and/or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities, and/or (3) Planned or controlled interruption of any additional Load required to mitigate the post-contingency results, provided that the non-consequential load being shed for the event is localized, and provided that the total load shed for the event does not exceed 2% of the Planned system peak demand or 200 MW, whichever value is less."

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The SDT did not adopt numerical limits as a single nation-wide value was not seen as equitable for all entities.

Footnote 'b' now reads:

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- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

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Organization	Yes or No	Question 1 Comment
Hydro-Québec TransEnergie	No	The proposed changes do not adequately address FERC's concerns in RM06-16-009. The Commission

Organization	Yes or No	Question 1 Comment
(HQT)		again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." The proposed changes to footnote 'b' indicate "No interruption of firm Load is allowed except:... (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities." The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as "the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency." In referencing Order 693, the Commission reiterated its position that TPL standards "should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." "Must" should be used instead of "should" in the last sentence of the footnote, making it to read "Facility Ratings in those regions must also be respected."
Northeast Power Coordinating Council	No	The proposed changes do not adequately address FERC's concerns in RM06-16-009. The Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." The proposed changes to footnote 'b' indicate "No interruption of firm Load is allowed except:... (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities." The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as "the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency." In referencing Order 693, the Commission reiterated its position that TPL standards "should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." "Must" should be used instead of "should" in the last sentence of the footnote, making it to read "Facility Ratings in those regions must also be respected."
Response: The SDT believes that it has been responsive to the FERC directive in that the standards development process has been employed. In the development of the footnote, the SDT has balanced the need for discretion while addressing local area concerns with the need to assure the reliability of the BES.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3">
‘Must’ is not appropriate in a footnote as it would impose a requirement in the footnote. The SDT has replaced ‘should’ with ‘would’ to correct the grammar.

Footnote ‘b’ now reads:

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</td></tr>
<tr><td>Tri-State Generation and Transmission Association, Inc.</td><td>No</td><td>Tri-State does believe that the new footnote is an improvement, but thinks there are still some changes necessary. We believe that the word “only” should be removed from the phrase “...where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities” because that discrimination was not required in FERC Order RM-06-16-009. There may be times when facilities near the temporary radial facilities might also fall outside the limits set in reliability criteria but the situation is mitigated if the load shedding occurs at the radial facility.

The meaning of the second paragraph of the new footnote is unclear. Tri-State recommends changing it to "Curtailment of Firm Transmission Service is not allowed unless it is coupled with curtailment-offsetting resources that are obligated to re-dispatch. Further, the curtailment activities cannot result in the shedding of any Firm load or in violations of Facility Ratings, either internal or external to the planning region."</td></tr>
<tr><td colspan="3">Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the</td></tr>
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<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3">various industry concerns while assuring BES reliability.

The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

Footnote ‘b’ now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

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<tr><td>Southern Company Transmission</td><td>No</td><td>We propose that the section in double parentheses be deleted. The proposed wording by the drafting team seems to imply that the curtailment of firm transmission service is permitted to address single contingency constraints if coupled with the redispatch of network resources. The original language stated only that curtailments were permitted to prepare for the next contingency, not to address loading related to the initial contingency. The proposed wording could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint.

Southern Companies recommend that the original language relating to “preparing for the next contingency” be incorporated into the drafting team’s proposal.((Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		curtailments of contracted Firm (non-recallable reserved) electric power Transfers.)) No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch. where it can It must be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

Response: The SDT believes that System re-dispatch is an acceptable System adjustment to "remain within applicable Facility Ratings" to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

Footnote 'b' now reads:

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		~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
South Carolina Electric & Gas	Yes	For better clarity delete the phrase "when coupled with" in the second paragraph of footnote 'b.'
Response: The SDT did not delete the suggested phrase as it believes it is correct as stated but added commas to make the phrase read more clearly. Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Independent Electricity System Operator	Yes	IESO supports the revisions made to footnote 'b' based on the present definitions of BES and Firm Demand and on the understanding that the NERC standards apply only to the BES as defined in the NERC Glossary as follows:"As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." To be clear, our interpretation of the present definition of BES is

Organization	Yes or No	Question 1 Comment
		that it defers to each Regional Reliability Organization to define the elements of the power system that are considered BES and, therefore in the NPCC Region, "BES as defined by NERC" = "BPS as defined by NPCC".

Response: The SDT agrees that the standard applies to the BES as defined in the Glossary.

Organization	Yes or No	Question 1 Comment
BPA, Transmission Reliability Program	Yes	On the firm transfer issues, the term "Firm Transmission Service" should be replaced with "Firm Transfers" to be consistent with the fourth column of the existing Table 1 Transmission System Standards - Normal and Emergency Conditions.

Response: The SDT agrees and has made the change.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
American Electric Power	Yes	

Organization	Yes or No	Question 1 Comment
Exelon Transmission Strategy & Compliance	Yes	
Florida Municipal Power Agency	Yes	
IESO	Yes	
Northeast Utilities	Yes	
Pepco Holdings, Inc.	Yes	
US Bureau of Reclamation	Yes	
Manitoba Hydro	Yes	MH agrees with the SDT proposal.
Ameren	Yes	We were ok with the previous language. Though we do not intend to drop non-consequential load for a single contingency, we undersatnd that other ares may have been following such practice without degarding the relaibility of BES. We believe that they can continue this practice if they develop non-firm contracts with these customers.
Response: Thank you for your support. Several stakeholders proposed additional modifications and the drafting team did make several additional modifications to the footnote – please see the revised footnote.		

2. Are you aware of any conflicts caused by compliance with the proposed language in Table 1 — footnote b and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement? If yes, please identify the conflict.

Summary Consideration: The SDT understands that there may be conflicts as pointed out by respondents; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES. Strict numerical constraints applied across all of North America were not seen as appropriate. Instead, the SDT is leveraging existing processes to require documentation of Demand to be interrupted including alternatives evaluated and for the situation to be vetted in an open and transparent stakeholder process.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

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- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 2 Comment
Ameren	No	

Organization	Yes or No	Question 2 Comment
American Electric Power	No	
American Transmission Company	No	
BPA, Transmission Reliability Program	No	
Dairyland Power Cooperative	No	
Exelon Transmission Strategy & Compliance	No	
Independent Electricity System Operator	No	
Manitoba Hydro	No	
Midwest Reliability Organization	No	
Southern Company Transmission	No	
US Bureau of Reclamation	No	
South Carolina Electric & Gas	No	The comments expressed herein represent a consensus of the views of the above named members of the SERC Engineering Committee Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.
Response: Thank you for your response. Several stakeholders proposed additional modifications and the drafting team did make several additional modifications to the footnote – please see the revised footnote.		
Hydro-Québec TransEnergie (HQT)	Yes	Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict

Organization	Yes or No	Question 2 Comment
		between state and federal positions could place utilities in a compromising position.
Northeast Power Coordinating Council	Yes	Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.
IESO	Yes	It should be noted that conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. In RM-06-16-009, the Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." In the US, State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.Similar conflicts may also exist in Canada.
Progress Energy	Yes	There is the potential for conflict between Table 1 - Footnote (b) as currently proposed, which can be considered to regulate local distribution reliability without improving BES reliability, and local service reliability issues which are under the purview of state regulatory agencies. For example, the North Carolina Utilities Commission (NCUC) commented regarding this concern in the ballot which ended March 1 in Project 2006-02. Specifically, NCUC commented that they were "...concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1 is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions..." Progress Energy believes that NCUC's concerns are legitimate. BES reliability should address the avoidance and mitigation of cascading outages and BES facility damage, rather than limited, controlled local area loss of load, in order to avoid this conflict and overlap of regulation.
Response: The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES. Strict numerical constraints applied across all of North America were not seen as appropriate. Instead, the SDT is leveraging existing processes to require documentation of Demand to be interrupted including alternatives evaluated and for the situation to be vetted in an open and transparent stakeholder process.		

Organization	Yes or No	Question 2 Comment
Northeast Utilities	Yes	Northeast Utilities (NU) believes the language of the proposed revision to footnote 'b' can be better defined as the proposed revision is subject to interpretation by the different entities and regulatory agencies. Future conflicts can be minimized by further clarifying the proposed revision. Also, NU is concerned that this new modification does not specify the amount of permissible load shed nor does it require the planning entity to minimize load shedding under this exception.

Response: The SDT has made several clarifying changes to the footnote which should alleviate your concerns.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 2 Comment
Duke Energy	Yes	See response to question #1.
Georgia Transmission Corporation (Bulk System Planning)	Yes	See response to Question #1.

Organization	Yes or No	Question 2 Comment
Response: See response to question #1.		
Florida Municipal Power Agency	Yes	This is an area of fuzziness between State jurisdiction and Federal jurisdiction. In all honesty, shedding load for local area impacts has nothing to do with BES reliability and should not be under FERC jurisdiction under Section 215 of the Federal Power Act, but rather State jurisdiction for quality of service issues. However, there is also the matter of FERC jurisdiction over commercial matters and the opportunity to "game" the original footnote by transmission providers by allowing firm load shedding to grant firm transmission service for themselves, thereby avoiding or deferring transmission investment, while at the same time denying or requiring others to build the same transmission avoided in order to obtain transmission service. We can see how difficult it is from a drafting team's perspective in achieving a balanced position between these different matters. The drafting team should be applauded for finding a reasonable position.
Pepco Holdings, Inc.	Yes	This is not an issue for historic PJM members, but as PJM has expanded and as a result of the merger of historic councils into RFC, I am aware that not all regions had standards equal to those of MAAC, and this has been an issue worked out between transmission planners (historic transmission owners) and their local regulators. It is ultimately a cost issue for loss of local load that does not affect the overall reliability of the interconnected BES.
Response: Thank you for your support.		
Tri-State Generation and Transmission Association, Inc.	Yes	We believe that FERC's directive in FERC Order RM-06-16-009 to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load.
Response: The SDT is not in a position to comment on FERC's authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES. Such constraints would be determined through the open and transparent stakeholder process.		

3. Consideration of Comments on Initial Ballot — TPL Table 1 Order (Project 2010-11) May 17–27, 2010

Summary Consideration: The SDT has listened to the comments from the industry, understands the concerns raised, and has made changes to the footnote to balance the various industry concerns while assuring BES reliability.

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT from the cited inputs that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when load could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could

you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in this 2nd posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that likely will be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote 'b' to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~

o Interruptible Demand or Demand-Side Management

o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Rodney Phillips	Allegheny Power	1	Negative	Allegheny Power believes the loss of non-consequential load and/or curtailment of transmission service for N-1 contingencies should be limited to only extreme circumstances. Exception 2 of footnote b allows for the loss of non-consequential load for N-1 contingencies with no restriction. Allegheny Power recommends removing exception 2 footnote b.
Response: The SDT and the majority of the commenters disagree with this suggestion.				
Gordon Rawlings	BC Transmission Corporation	1	Negative	BCTC appreciates the good work of the SAR committee in drafting the changes to Footnote b of Table 1. BCTC agrees with the drafting team that interruption of firm load, served by either radial circuits or circuits that have became radial as a result of the contingency, should be allowed for N-1 contingencies. However, it is our position that interruption of firm load should not be limited only to such consequential loads. In our view, interruption of electric supply to some local network customers in the affected area should be permissible. This inclusion will allow transmission planners to plan BCTC's regional transmission network reliably and without impacting neighbouring transmission networks.
Faramarz Amjadi	BC Transmission Corporation	2	Negative	
Hubert C. Young	South Carolina Electric & Gas Co.	3	Negative	SCE&G has significant concern with the proposed revision to TPL Table 1, Footnote B. The current Footnote B states "Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted

Voter	Entity	Segment	Vote	Comment
				element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems". The phrase "without impacting the overall reliability of the interconnected transmission systems" is important to the TPL standards to ensure that ERO standards do not dictate the level of service to customers. Service to customers and load pockets is jurisdictional to State Commissions and ERO standards should not compromise this jurisdiction. SCE&G believes that any proposed revisions to Footnote B must retain the concept that planned or controlled interruption of electric supply to customers, whether they are radial or network, is allowed as long as it does not impact the overall reliability of the interconnected transmission systems. The proposed revision eliminates this concept. There seems to be a general inconsistency and maybe confusion between the terms "reliability" and "level of service".
David Frank Ronk	Consumers Energy	4	Negative	The current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the previous version of TPL-001-1. However, it still does not allow Transmission Planners to use appropriate and necessary discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should control the decision making when BES reliability is not an issue. Often, the consequences of these events are solely local in nature, requiring only minor additional loss of local load to avoid the costly major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load.
James B Lewis	Consumers Energy	5	Negative	
Hugh A. Owen	Public Utility District No. 1 of Chelan County	6	Negative	The interruption of a small amount of load is, under most conditions, not a risk to the reliability of the BES and is at times necessary to preserve reliability. The planned interruption of some load may be a cost effective alternative to a costly transmission project. That is a quality of service issue.
Michael Gammon	Kansas City Power & Light Co.	1	Negative	While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit
Charles Locke	Kansas City Power & Light Co.	3	Negative	
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	

Voter	Entity	Segment	Vote	Comment
				point of view to allow loss of non-consequential load.
Linda Brown	San Diego Gas & Electric	1	Affirmative	As to item (1), all load served directly by a transmission element which experiences a fault will be interrupted when the faulted element is taken out of service. This is the natural relationship between the load and the transmission element. Allowing this for BES elements may encourage transmission owners to remove transmission instead of upgrading or replacing it. Consider a load supplied by two transmission lines of different capacity. If the larger line is lost due to a contingency (N-1) and the remaining smaller line overloads the transmission owner is left with several options to address the problem: (1) move load between buses, (2) upgrade the smaller line, (3) add another line, or (4) create a radial load by removing the smaller line. Number (4) may be the least expensive and allowable under TPL-002, footnote b. Item (2) may also encourage transmission owners to develop plans which make load shedding part of category B. Consider a load served by three transmission lines, a utility may decide to remove a line, instead of upgrading, in order to set up a situation where an N-1 contingency would make the bus temporarily radial. In the event of a single outage (N-1), the load bus will be temporarily radial and load can be shed at the bus.
W. R. Schoneck	Florida Power & Light Co.	3	Affirmative	I believe the language is an improvement and clarifies the intent but I believe there still should be additional language added to give an exemption in meeting this requirement if it does not make economic sense(not economically feasible) and has no real impact on the BES.
Richard J Kafka	Potomac Electric Power Co.	1	Affirmative	It is understood that this is a compliance filing issue. This is not an issue for historic PJM members, but as PJM has expanded and as a result of the merger of historic councils into RFC, I am aware that not all regions had standards equal to those of MAAC, and this has been an issue worked out between transmission planners (historic transmission owners) and their local regulators. It is ultimately a cost issue for loss of local load that does not affect the overall reliability of the interconnected BES.
Alan Gale	City of Tallahassee	5	Affirmative	TAL thanks for SDT for the tireless effort to get to this point. TAL is voting affirmative with the following comments. We accept that the loss of non-consequential load is not a desired result for N-1 contingencies. It is also not the norm in system planning or operations. The flexibility to operate the system consistent with “good utility practice” may warrant the “odd-ball” case that would require this to occur. The dropping of non-consequential load

Voter	Entity	Segment	Vote	Comment
				will NOT lead to BES instability, voltage collapse, or cascading outages, which is what FERC and NERC are charged with preventing. It will lead to the shedding of load in a local area only. Utilities do not drop customers lightly. If the meter isn't turning, we are not getting paid, so we want the meter spinning. Utility power, while vital to our normal day-to-day lives and infrastructure, was never intended to be without interruption.
Brad Chase	Orlando Utilities Commission	1	Affirmative	This change raises the bar on transmission system performance. This change applies a blanket requirement upon entities that does not take into account the number of outages, probability of outages or cost to the customer. There are certain to be situations where this blanket requirement will result in increased cost to customers for no noticeable increase in reliability. OUC does agree with the concept of greater clarification on this requirement, however this clarification may raise the bar to far by trying to establish a blanket requirement. Duke, Progress Energy and others will be submitting comments with proposed language that attempt to address some of these issues and we encourage the drafting team to consider those comments.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

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- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of

Voter	Entity	Segment	Vote	Comment
resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
Eric Egge	Black Hills Corp	1	Negative	Black Hills believes that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Chifong L. Thomas	Pacific Gas and Electric Company	1	Negative	PG&E commends the SDT for developing the proposed footnote b. While it is a great improvement over the complete prohibition on loss of non-consequential load for any single contingency, the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system, especially where the impact is local in nature, to avoid instability, cascading or uncontrolled separation. Such planned interruption of load may be a reasonable alternative to the environmental impacts or prohibitive costs associated with a major new transmission project. Given the potential impacts of the proposed modification, further vetting of the issues is needed. PG&E believes that NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.

Voter	Entity	Segment	Vote	Comment
Thomas J. Bradish	RRI Energy	5	Negative	RRI supports the WECC position on this issue; namely, that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Trent Carlson	RRI Energy	6	Negative	
John Tolo	Tucson Electric Power Co.	1	Negative	The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project.
James Tucker	Deseret Power	1	Negative	The prohibition of loss of non-consequential load for events resulting the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including

Voter	Entity	Segment	Vote	Comment
				customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Louise McCarren	Western Electricity Coordinating Council	10	Negative	The proposed revisions to footnote b of Table 1 are an improvement to the recently balloted prohibition on loss of non-consequential load for single contingencies. The recognition of the new term "temporarily radial" is a step in the right direction. However, the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
William Mitchell Chamberlain	California Energy Commission	9	Negative	While the proposed revisions to footnote b are an improvement to the prohibition on loss of non-consequential load for a single contingency proposed in the recently failed TPL-001-1 ballot, the prohibition of loss of non-consequential load for events resulting the loss of a single element still inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is

Voter	Entity	Segment	Vote	Comment
				local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
John Mick	Colorado Springs Utilities	6	Negative	Colorado Springs Utilities ballot on the proposed changes to TPL Table 1, footnote b directed in FERC Order RM06-16-009 Colorado Springs Utilities wishes to vote NO on the proposed changes to TPL Table 1, footnote b, directed in FERC Order RM06-16-009. CSU concurs with the WECC position paper for the ballot, and agrees with the WECC statement "that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues".

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

The SDT agreed that a technical conference on this issue would be of value and held such a conference on August 10, 2010.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and

Voter	Entity	Segment	Vote	Comment
				~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Horace Stephen Williamson	Southern Company Services, Inc.	1	Negative	Comments have already been submitted previously, but it will be added here again. Proposed footnote should read... No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers when coupled with the appropriate re-dispatch of resources obligated to re-dispatch. It must be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. The proposed changes are based on the following... "The proposed wording by the drafting team seems to imply that the curtailment of firm transmission service is permitted to address single contingency constraints if coupled with the redispatch of network resources. The original language stated only that curtailments were permitted to prepare for the next contingency, not to address loading related to the initial contingency. The proposed wording could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint. Southern Companies recommend that the original language relating to "preparing for the next contingency" be incorporated into the drafting team's proposal."
Richard J. Mandes	Alabama Power Company	3	Negative	
Anthony L Wilson	Georgia Power Company	3	Negative	
Gwen S Frazier	Gulf Power Company	3	Negative	
Don Horsley	Mississippi Power	3	Negative	
Michael Ibold	Xcel Energy, Inc.	3	Negative	The proposed modification to footnote b of Table I in TPL-001 - 004 standards states that after a Category B contingency, there should not be any thermal, voltage or stability violation, no interruption of firm load (except the load that is directly connected to the elements that are removed from service as a result of the contingency) and no firm transfer curtailment (except when coupled with re-dispatch of resources obligated to re-dispatch). We believe the proposed footnote b creates a gap between TPL-002 and TPL-003 standards, since it does not address conditions when firm load shedding and firm transfer curtailments are not required to meet the system performance for Category B contingency, but one or both are the required system adjustments to prepare for the next contingency (Category C3). When firm transfer is curtailed after the first contingency in
Liam Noailles	Xcel Energy, Inc.	5	Negative	
David F. Lemmons	Xcel Energy, Inc.	6	Negative	

Voter	Entity	Segment	Vote	Comment
				preparation for the next contingency, it is not clear from the proposed footnote b if this is considered a valid system adjustment for Category C or a violation of Category B. Recall that the existing footnote b addresses this condition explicitly by stating “To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm Transfers.”
George T. Ballew	Tennessee Valley Authority	5	Affirmative	TVA appreciates the work of the SDT on this issue. However, TVA recommends revising the second paragraph of the revised footnote b: “To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. However, curtailment of Firm Transmission Service is only allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions should also be respected.” Without the changes in the first two sentences above, the proposed wording by the SDT could be interpreted to allow re-dispatch/firm curtailments to address any single contingency constraint instead of in preparation for the next contingency.
Marjorie S. Parsons	Tennessee Valley Authority	6	Affirmative	
Larry Akens	Tennessee Valley Authority	1	Affirmative	TVA appreciates the work of the SDT. However, TVA recommends revising the second paragraph of the revised footnote "b". Without changes in the first two sentences, the proposed wording by the SDT could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint instead of in preparation for the next contingency.

Response: The SDT believes that System re-dispatch is an acceptable System adjustment to “remain within applicable Facility Ratings” to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote ‘b’ clarifies that re-dispatch is allowable to “remain within” ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words “To prepare for the next Contingency” to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

Footnote ‘b’ now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand.

Voter	Entity	Segment	Vote	Comment
				Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Robert W. Roddy	Dairyland Power Coop.	1	Negative	DPC CONCURS WITH THE MRO COMMENTS.
Jason Shaver	American Transmission Company, LLC	1	Affirmative	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed if the tripping of the load is either accepted or volunteered by the customer.
Lawrence R. Larson	Otter Tail Power Company	1	Negative	The change precludes the use of direct load control systems that should be allowed to relieve transmission problems. These systems control firm transmission load but rate conditions can allow their use to mitigate transmission problems.
Response: *(Note - MRO did not submit comments with the initial ballot – but did submit the following comment during the formal comment period: For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.)*				

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td colspan="5">The SDT has modified the footnote to address your concern.

Footnote ‘b’ now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~

o Interruptible Demand or Demand-Side Management

o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

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<tr><td>Ajay Garg</td><td>Hydro One Networks, Inc.</td><td>1</td><td>Negative</td><td rowspan="2">Hydro One is casting a negative vote for the following reasons:

1. The amendment to the footnote does not add any technical value to the standard. It was added only to satisfy a FERC directive to address comments made to allow non-consequential load loss after a single contingency event, “based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios.”

2. Addressing curtailment of Firm Transmission Service with re-dispatch of resources is a matter of a commercial nature and should be dealt with in the agreements dealing with such services. Issues of contracted transmission services, firm or otherwise, are not a reliability related matter and are not to be dealt with in this standard.</td></tr>
<tr><td>Michael D. Penstone</td><td>Hydro One Networks, Inc.</td><td>3</td><td>Negative</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
				3. Matters of interruption of firm load should be incorporated into this standard only after the FERC NOPR on the definition of the BES is resolved. As it stands, the footnote will pose significant problems if the 100 kV and above FERC proposal is applied across the board, unless the standard specifically states that it applies to the BES as defined by the region (current definition).

Response: 1. & 2. The SDT disagrees. The SDT believes that there could be a direct impact on reliability of the BES associated with uncontrolled interruption of Demand and that it is important to discourage and limit the use of this option.The SDT has added clarity to the footnote.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

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- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

3. The SDT disagrees that this needs to wait on the FERC NOPR. This standard is applicable to the BES as it is defined.

Voter	Entity	Segment	Vote	Comment
Spencer Tacke	Modesto Irrigation District	4	Negative	I am voting NO vote because of the lack of clarity of the second paragraph of the proposed change. Although paragraph 1 is an improvement to the current wording, and actually allows for some specific flexibility in shedding load for an N-1 event, the lack of clarity in the second paragraph could lead to varied interpretations by members and compliance

Voter	Entity	Segment	Vote	Comment
				auditors. Thank you.

Response: The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

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- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Dana Cabbell	Southern California Edison Co.	1	Negative	It is SCE's position that the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local
David Schiada	Southern California Edison Co.	3	Negative	

Voter	Entity	Segment	Vote	Comment
Ahmad Sanati	South California Edison Company	5	Negative	regulator input, for their individual system. When planned load interruption is identified as a response to a single event, the impact to the system is often local in nature. The planned interruption of load may be a desirable alternative to the prohibitive costs associated with a major new transmission project. If the NERC Standards Drafting Team decides to proceed with footnote B, as written, it needs to ensure that Transmission Owners, Transmission Operators, and Transmission Planners have enough time to both design and implement any mitigation plans necessary to be compliant with the new language. In almost all cases the actual implementation of a solution requiring new construction will be dependent on a number of different regulatory agencies providing the necessary permits allowing for its construction. As such, NERC needs to ensure that any time frame associated with compliance to the proposed language be variable, and allow for extended implementation time frames based on system conditions that may delay placing mitigation plans in service. An example of a reasonable variable time frame to be compliant with the proposed language in footnote B would be to start the clock 60 months from receiving the pertinent environmental permitting. In California this could be the issuance of a Draft Environmental Impact Review pursuant to the California Environmental Quality Act.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

The SDT has added more latitude for the Transmission Planner with the modifications and believes that 60 months should be sufficient.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

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- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the~~

Voter	Entity	Segment	Vote	Comment
				~~Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Henry Ernst-Jr	Duke Energy Carolina	3	Negative	On the initial ballot of TPL-001-1 Duke Energy also voted "Negative", primarily because Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We also sought rehearing on the Commission's March 18 Order Setting Deadline for Compliance (Docket No. RM06-16), with respect to this and other issues. We believe that FERC's directive in that Order to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the potential impacts (environmental, historical, archaeological, aesthetic...) of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. With this "Negative" vote, Duke

Voter	Entity	Segment	Vote	Comment
				offers the following ideas on alternatives for the SDT to consider that will allow for appropriate discretion and facilitate proper planning while allowing non-consequential load loss (NCLL). The standard should allow for dropping of limited amounts of non-consequential load in situations where it would be reasonable for a bounded time period and under restricted system conditions (e.g. 1-3 years only when load is >90 % of peak conditions). Dropping of non-consequential load would be prudent planning in situations where the near term impact of load projections or implementation of nearby transmission/generation projects will alleviate the necessity of an upgrade to meet N-1 conditions. Also, reliability of service to end-use customer is impacted by the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customers' level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to avoid projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics (e.g. SAIFI/SAIDI/ASAI) should also be considered by the SDT for determination of acceptable use of NCLL.
Luther E. Fair	Gainesville Regional Utilities	1	Affirmative	Even though I am voting in the affirmative, I agree that most of the comments offered by Duke and Norther Indiana in their earlier statements have merit and should be considered. Also, I believe that the use of reliability metrics should be considered by the SDT for determination of acceptable use of NCLL.
Mace Hunter	Lakeland Electric	3	Negative	Reliability should consider the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customer's level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to delay projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics should also be considered by the SDT for determination of acceptable use of NCLL.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

Voter	Entity	Segment	Vote	Comment
Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch do~~es~~ not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
Sammy Roberts	Progress Energy Carolinas	1	Negative	Progress Energy applauds NERC's efforts to improve the footnote (b) language with respect to conditional allowance of curtailing Firm Transmission Service, which is addressed in the second paragraph of the proposed new footnote (b). PE remains concerned, however, that the first paragraph of the proposed new footnote (b) does not allow for curtailment of non-radial non-consequential load. The ability to curtail non-consequential load in the planning horizon can be a useful tool to mitigate local area issues, and has not been detrimental to
Lee Schuster	Florida Power Corporation	3	Negative	

Voter	Entity	Segment	Vote	Comment
Sam Waters	Progress Energy Carolinas	3	Negative	the Bulk Electric System (BES). Disallowing the curtailment of non-radial non-consequential load essentially prohibits taking action in situations in which the load in question is clearly at a localized self-contained level of the system, i.e. the distribution system(s) served by the Transmission Owner. Prohibiting the curtailment of local load thus constitutes regulating distribution feeder reliability rather than BES reliability. Events that could be mitigated through the curtailment of local, non-radial non-consequential load are infrequent, and such curtailment has no material effect on the reliability of the BES. PE therefore suggests that the following addition (item (3)) to the first paragraph of the proposed footnote (b) be considered: "No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, and/or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities, and/or (3) Planned or controlled interruption of any additional Load required to mitigate the post-contingency results, provided that the non-consequential load being shed for the event is localized, and provided that the total load shed for the event does not exceed 2% of the Planned system peak demand or 200 MW, whichever value is less."
Wayne Lewis	Progress Energy Carolinas	5	Negative	

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The SDT did not adopt a numerical limit as it believes that any single numerical value applied on a ntion-wide basis was not equitable for all entities.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial~~

Voter	Entity	Segment	Vote	Comment
				~~Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Timothy VanBlaricom	California ISO	2	Negative	The California ISO supports NERC's request for a public technical conference to be held, as described in NERC's April 19, 2010 request for rehearing and motion for stay of the March 18 Order (RM06-16-009), to provide the opportunity to gain industry input and written comments regarding the Commission's TPL-002-0 directive for NERC to develop a modification to the TPL-002-0 Table 1 footnote b.
Response: The SDT agreed that a technical conference would be of value and held such a conference on August 10, 2010.				
Terry L. Blackwell	Santee Cooper	1	Negative	The Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning processes appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. Table B footnote still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, and local customers should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. The Commission's directive sets forth an expectation that NERC is to implement standards that address all loss of load at costs that may not be commensurate with bulk power system reliability, as statutorily defined, which is fundamentally different from what the Reliability Standards were intended to do.
Zack Dusenbury	Santee Cooper	3	Negative	
Suzanne Ritter	Santee Cooper	6	Negative	

Response: The SDT is not in position to comment on FERC's authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.

Voter	Entity	Segment	Vote	Comment
Kimberly J. Jones	North Carolina Utilities Commission	9	Negative	The NC Utilities Commission is concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1, and as explained in draft footnote b, is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions. This requirement does not provide any benefit to reliability of the bulk electric system and could undermine state efforts to balance reliability issues with cost of service issues. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load, understanding that state commissions are positioned to force electric utilities to address local service quality issues on an expedited basis, should it be necessary and in the public interest.

Response: The SDT understands the concern but believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES. The SDT's approach will leverage existing processes to document and vet the situation.

Footnote 'b' now reads:

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- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

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Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Negative	THE PROPOSED INTERPRETATION WILL UNDERMINE THE INTERNATIONAL STANDARDS SETTING PROCESS AND COULD RESULT IN DIFFERING INTERPRETATIONS OF STANDARDS ON THE NORTH AMERICAN BULK-POWER SYSTEM.
Response: The SDT disagrees and believes that the footnote has been clarified appropriately within the standards development process.				
Daryn Barker	Louisville Gas and Electric Co.	6	Negative	The revised footnote b on Table 1 imposes additional requirements on the responsible entities. The footnote states: Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. However, R1 states: The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned These statements address different and inconsistent scope. If the change in scope was intended then a change should also be made to R1 to reconcile the inconsistency.
Charlie Martin	Louisville Gas and Electric Co.	5	Negative	Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. However, R1 states: The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned These statements address different and inconsistent scope. If the change in scope was intended then a change should also be made to R1 to reconcile the inconsistency.
Response: The SDT agrees that your assessment is for your portion of the interconnected grid. However, when performance in one system is dependent on generation dispatch in another system or vice versa, the SDT believes that one must ensure that the re-dispatch is feasible. The SDT does not believe that this presents a conflict with Requirement R1.				
John Apperson	PacifiCorp	3	Negative	This proposal warrants a "no" vote due to the current uncertainty regarding the outcome of the FERC TPL-002 NOPR issued by FERC on March 18, 2010. The impacts of the proposed changes to footnote B cannot be assessed separately from the alternative interpretation of TPL-002 proposed by FERC. The proper planning of a transmission system requires that all performance requirements are known and understood. If only some of the requirements are known and understood it is impossible to properly plan, study, assess, and operate the

Voter	Entity	Segment	Vote	Comment
				transmission system.
Response: The current TPL-002 is in force and will remain so until the completion of the cited FERC NOPR. This limited scope revision to footnote 'b' is to add clarity to what is in effect.				
Keith V. Carman	Tri-State G & T Association Inc.	1	Negative	Tri-State does believe that the new footnote is an improvement, but thinks there are still some changes necessary. We believe that the word "only" should be removed from the phrase "...where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities" because that discrimination was not required in FERC Order RM-06-16-009. There may be times when facilities near the temporary radial facilities might fall outside the limits set in reliability criteria but the situation is mitigated if the load shedding occurs at the radial facility. The meaning of the second paragraph of the new footnote is unclear. Tri-State recommends changing it to "Curtailment of Firm Transmission Service is not allowed unless it is coupled with curtailment-offsetting resources that are obligated to re-dispatch. Further, the curtailment activities cannot result in the shedding of any Firm load or in violations of Facility Ratings, either internal or external to the planning region." We believe that FERC's directive in FERC Order RM-06-16-009 to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.				

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o Interruptible Demand or Demand-Side Management

o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

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The SDT is not in position to comment on FERC’s authority.</td></tr>
<tr><td>Claudiu Cadar</td><td>GDS Associates, Inc.</td><td>1</td><td>Negative</td><td>We do not agree with the proposed changes due to several reasons. Although the proposed change will directly influence the reliability standards and transmission system performances, will also have an indirect impact on the economic side with respect to the expansion of existing transmission system. We believe that FERC directive as stipulated in Order 693 cannot constrict, nor impose certain actions outside of the reliability limits. We believe that since these events are merely isolated and rarely enforced, the decision of mandating a great financial effort as a consequence of the proposed changes would certainly be counterbalanced by its feasibility when compare with the current cost of load shedding. While the revised footnote b can be certainly considered an improvement from the current version, however it still does not allow the joined entities involved to have power over the decision making when BES reliability is not an issue.

We also believe that any mandatory changes implemented in the TPL standards under the</td></tr>
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Voter	Entity	Segment	Vote	Comment
				current scenario are not entirely feasible unless all other issues such as the definition of the BES, Consequential / Non-consequential Load, BES Critical Element, etc gets resolve ahead. The revision with respect to load shedding, specifically the portion about shedding loads on newly radial facilities, does not match the version 1 TPL standard definition of consequential load loss. To approve the proposed revision to footnote 'b' would create an unnecessary discrepancy between the version 1 TPL standard under consideration and the existing standards. We recognize that the Version 1 will replace Version 0, but since it appears that the performance standard with respect to footnote 'b' is intended to be same in the revised footnote and the Version 1 standard, it only makes sense that the revised version 0 footnote 'b' match the consequential load loss definition contemplated in Version 1. In the light of the above we suggest the Commission to approach different other solutions and ideas for improving the current reliability of the transmission system without enforcing decisions beyond its statutory scope. We advance an alternative to this matter meant to balance the reliability of the transmission system and its indirect financial impact. Although the solution that we offer would require an extended time for development and implementation, however we urge NERC to consider it in its further approach. Our alternative consists mainly in implementing an additional term such as "Critical Load" which we have briefly figured that would consist in particular load necessary to be maintained in service without interruption. Even though this new term would seemed to be at first related with the quality of the service, however a joint association of transmission planners, customers, regulatory entities as decision makers can simply individualize the load that cannot be shed, as well as future transmission improvements that will be required to serve this envisioned small amount of load rather than the entire load. In this way we will create a reasonable balance in between the reliability of the transmission system and the cost to maintain / improve this reliability.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When

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interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
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- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

The current TPL-002 is in force and will remain so for the forseeable future. This limited scope revision to footnote 'b' is to add clarity to what is in effect.

Project 2006-02 is under revision and the clarifications of footnote 'b' will be considered by the SDT for future revisions of TPL-001-2.

The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

Ronald D. Schellberg	Idaho Power Company	1	Negative	While the proposed revisions are an improvement to the prohibition on loss of non-consequential load for a single contingency proposed in the recently failed TPL-001-1 ballot, that the prohibition of loss of non-consequential load for events resulting the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. However, the removal of: "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." will require significant adjustments in either TRM or TTC reductions to be compliant with this revised standard in the WECC Region. To construct additional transmission facilities to maintain present day business could easily exceed 10 Billion dollars throughout the WECC region. For example, the Pacific AC Intertie currently has a TTC of 4800 MW spread across 3 500 kV transmission lines. With the loss of one Transmission line, the Pacific AC intertie drops to 3200 MW. Removal of this sentence

Voter	Entity	Segment	Vote	Comment
				would require TP either to drop the Firm TTC of the Intertie to 3200, or include a TRM reservation of at least 1600 MW. The TPs would not be able to say that a loss of 1600 MW of import capacity would not result in curtailments of firm load. Just about all multi transmission line paths in the WECC Region would suffer. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. In the case of long interties between subregions of WECC, these interties have never been planned to operate in this manner. Idaho Power recommends that the sentence permiting system adjustments be reinserted into Footnote B.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.

The SDT believes that System re-dispatch is an acceptable System adjustment to "remain within applicable Facility Ratings" to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

Footnote 'b' now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

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Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
Francis J. Halpin	Bonneville Power Administration	5	Affirmative	For consistency, regarding the firm transfer issue, the term "Firm Transmission Service" should be replaced with "Firm Transfers" in order to be consistent with the fourth column of the existing Table 1 "Transmission System Standards - Normal and Emergency Conditions".
Response: The SDT agrees and has made the change. Footnote 'b' now reads: ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application				

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Kim Warren	Independent Electricity System Operator	2	Affirmative	IESO supports the revisions made to footnote ‘b’ based on the present definitions of BES and Firm Demand and on the understanding that the NERC standards apply only to the BES as defined in the NERC Glossary as follows: “As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighbouring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.” To be clear, our interpretation of the present definition of BES is that it defers to each Regional Reliability Organization to define the elements of the power system that are considered BES and, therefore in the NPCC Region, "BES as defined by NERC" = "BPS as defined by NPCC".
Response: The SDT agrees that the standard applies to the BES as defined in the Glossary.				
Jacquie Smith	ReliabilityFirst Corporation	10	Affirmative	If this revision is an urgent action, then the implementation timeframe should be shorter. In the clarification paragraph below, I do not understand the first sentence. Are there commas missing? What is the requirement and what is the exception? Also, I question the validity of using “should” in the second sentence. If it is a requirement, then it needs to be stated as a requirement. If it is a suggestion, then it does not belong in the standard. No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions should also be respected.
Response: This was originally classified as an ‘urgent action’ revision to meet the FERC due date which was June 30, 2010, not because NERC had classified the modification as urgent for reliability. Note that FERC modified the due date to March 31, 2011 - this allows several more months of				

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<tr><td colspan="5">development time and the SAR was revised to indicate that the proposed modification to footnote ‘b’ is no longer an Urgent Action revision.

Commas have been added as appropriate and a re-wording was made which should make this clear.

‘Should’ has been replaced by ‘would’ to provide additional clarity.

Footnote ‘b’ now reads:

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<tr><td>David H. Boguslawski</td><td>Northeast Utilities</td><td>1</td><td>Affirmative</td><td>Northeast Utilities (NU) believes the language of the proposed revision to footnote ‘b’ can be better defined as the proposed revision is subject to interpretation by the different entities and regulatory agencies. Future conflicts can be minimized by further clarifying the proposed revision.

Also, NU is concerned that this new modification does not specify the amount of permissible load shed nor does it require the planning entity to minimize load shedding under this exception.</td></tr>
<tr><td colspan="5">**Response:** The SDT has made several clarifying changes to the footnote which should alleviate your concerns.</td></tr>
</table>

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o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
o Interruptible Demand or Demand-Side Management
o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
</td></tr>
<tr><td>Donald S. Watkins</td><td>Bonneville Power Administration</td><td>1</td><td>Affirmative</td><td rowspan="3">On the firm transfer issues, the term "Firm Transmission Service" should be replaced with "Firm Transfers" to be consistent with the fourth column of the existing Table 1 Transmission System Standards - Normal and Emergency Conditions.</td></tr>
<tr><td>Rebecca Berdahl</td><td>Bonneville Power Administration</td><td>3</td><td>Affirmative</td></tr>
<tr><td>Brenda S. Anderson</td><td>Bonneville Power Administration</td><td>6</td><td>Affirmative</td></tr>
<tr><td colspan="5">
Response: The SDT agrees and has made this change.

Footnote ‘b’ now reads:

~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand.
</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
				Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o Interruptible Demand or Demand-Side Management o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. ~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Frank Gaffney	Florida Municipal Power Agency	4	Affirmative	Please see FMPA comments submitted through the concurrent comment period for Project 2010-11
David Schumann	Florida Municipal Power Agency	5	Affirmative	
Response: Please see the response to FMPA comments above.				
Carter B Edge	SERC Reliability Corporation	10	Affirmative	The footnote makes clearer when load can be dropped for planning purposes. By making this footnote more specific, it supports reliability and helps stakeholders apply the TPL standards.
Response: Thank you for your support.				

Voter	Entity	Segment	Vote	Comment
Timothy Beyrle	City of New Smyrna Beach Utilities Commission	4	Affirmative	This is an area of fuzziness between State jurisdiction and Federal jurisdiction. In all honesty, shedding load for local area impacts has nothing to do with BES reliability and should not be under FERC jurisdiction under Section 215 of the Federal Power Act, but rather State jurisdiction for quality of service issues. However, there is also the matter of FERC jurisdiction over commercial matters and the opportunity to "game" the original footnote by transmission providers by allowing firm load shedding to grant firm transmission service for themselves, thereby avoiding or deferring transmission investment, while at the same time denying or requiring others to build the same transmission avoided in order to obtain transmission service. We can see how difficult it is from a drafting team's perspective in achieving a balanced position between these different matters. The drafting team should be applauded for finding a reasonable position.
Response: Thank you for your support.				
Larry E Watt	Lakeland Electric	1	Affirmative	This issue is better handled within the development of the new TPL-001 standard.
Response: The current TPL-002 is in force and will remain so until the completion of the TPL-001-2 effort. This limited scope revision to footnote 'b' is to add clarity to what is in effect.				

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on Project 2010-11: TPL Table 1 Order and Comments Submitted with Initial Ballots

The Standards Committee thanks all commenters who submitted comments on the proposed SAR for the TPL Table 1 Order. The SAR proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which requires the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards.

The SAR, implementation plan, and the clean and redline versions to the four TPL standards were posted for a 40-day public comment period from April 15, 2010 through May 27, 2010. Stakeholders were asked to provide feedback on the standards through a special electronic comment form. There were 22 sets of comments, including comments from more than 80 different people from approximately 40 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

The initial ballot for the proposed changes to the four TPL standards was conducted from May 17-27, 2010. The comments submitted with initial ballots and the drafting team's responses to those comments are also contained in this report.

All comments submitted during the comment period and the initial ballot results are posted on the following page:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Based on stakeholder comments, the drafting team has made some additional changes to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

The following bullet was added to Footnote 'b' to provide the flexibility requested by stakeholders with respect to interrupting Demand, but with appropriate constraints to protect reliability. The >90% demand level was selected to ensure that the number of hours with exposure to demand loss was not unlimited. A 90% demand level is a reasonably stressed case for most systems and the number of hours when peak demands are >90% is a small percentage of the time for most systems. A large percentage of the transmission lines that directly serve distribution customers are 161 kV or lower voltages. Ten percent (10%) of the loading on a high capacity 161 kV transmission line is approximately 50 MW.

- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW

The following bullet was added to Footnote 'b' to clarify that it is acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

The above changes will be noted to stakeholders before the initiation of the recirculation ballot.

The revised Footnote 'b' is:

b) No interruption of projected customer Demand is allowed except:

- o Interruption of Demand that is directly served by the elements that are removed from service as a result of the Contingency
- o Planned or controlled interruption of Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities
- o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- o Interruptible Demand or Demand-Side Management

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

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

Comments and Responses from Formal Comment Period:

Comments and Responses from Initial Ballot:

The Industry Segments are:

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

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
4.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
5.	Sylvain Clermont	Hydro-Quebec TransEnergie		1
6.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
7.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
8.	Ben Eng	New York Power Authority	NPCC	4
9.	Brian Evans-Mongeon	Utility Services	NPCC	8
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
15. Randy MacDonald			New Brunswick System Operator	NPCC					2				
16. Bruce Metruck			New York Power Authority	NPCC					6				
17. Lee Pedowicz			Northeast Power Coordinating Council	NPCC					10				
18. Robert Pellegrini			The United Illuminating Company	NPCC					1				
19. Saurabh Saksena			National Grid	NPCC					1				
20. Michael Schiavone			National Grid	NPCC					1				
2.	Group	Philip R. Kleckley	South Carolina Electric & Gas	X		X		X					
Additional Member			Additional Organization	Region					Segment Selection				
1. Bob Jones			Southern Company Services - Trans.	SERC					1				
2. David Marler			Tennessee Valley Authority	SERC					1				
3. Charles Long			Entergy	SERC					1				
4. James Manning			North Carolina Electric Membership Corporation	SERC					3				
5. Pat Huntley			SERC Reliability Corporation	SERC					10				
3.	Group	John Bee	Exelon Transmission Strategy & Compliance	X		X		X					
Additional Member			Additional Organization	Region					Segment Selection				
1. Mortenson, Eric			:(ComEd)	RFC					1				
2. Weaver, David W			(PECO)	RFC					1				
3. McHugh, Kathleen P			(PECO)	RFC					1				
4. Kay, Thomas W			(ComEd)	RFC					1				
5. Szymczak, Ronald			(ComEd)	RFC					1				
6. Chu, Ron F			(PECO)	RFC					1				
7. Donnelly, Michael J			(PECO)	RFC					1				
8. Kliros, Chris B			(ComEd)	RFC					1				
9. Mills, Paul M			(ComEd)	RFC					1				
10. Webb, Becky			(ComEd)	RFC					1				
4.	Group	Denise Koehn	BPA, Transmission Reliability Program	X		X		X	X				

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

Additional Member	Additional Organization	Region	Segment Selection
1. Chuck Matthews	BPA, Transmission Planning	WECC	1
2. Berhanu Tesema	BPA, Transmission Planning	WECC	1
3. Larry Furumasu	BPA, Transmission Planning	WECC	1
4. Kyle Kohne	BPA, Transmission Planning	WECC	1
5. Don Watkins	BPA, Transmission System Operations	WECC	1
6. Rebecca Berdahl	BPA, Power, Long Term Sales and Purchases	WECC	3

5.	Group	Carol Gerou	Midwest Reliability Organization										X

Additional Member	Additional Organization	Region	Segment Selection
1. Chuck Lawrence	American Transmission Company	MRO	1
2. Tom Webb	Wisconsin Public Service	MRO	3, 4, 5, 6
3. Terry Bilke	Midwest ISO Inc.	MRO	2
4. Jodi Jenson	Western Area Power Administration	MRO	1, 6
5. Ken Goldsmith	Alliant Energy	MRO	4
6. Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
7. Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
8. Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
9. Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
10. Scott Nickels	Rochester Public Utilities	MRO	4
11. Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6

6.	Group	Richard Kafka	Pepco Holdings, Inc.	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Jim Summers	Delmarva Power and Light Co.	RFC	1
2. John Radman	Potomac Electric Power Company	RFC	1

7.	Group	Ben Li	IESO		X								

Additional Member	Additional Organization	Region	Segment Selection

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1. Bill Phillips			MISO	MRO									
2. James Castle			NYISO	NPCC									
3. Charles Yeung			SPP	SPP									
4. Lourdes Estrada-Salinero			CAISO	WECC									
5. Patrick Brown			PJM	RFC									
6. Steve Myers			ERCOT	ERCOT									
8.	Group	Frank Gaffney	Florida Municipal Power Agency	X			X	X	X				
		Additional Member	**Additional Organization**	**Region**					**Segment Selection**				
1. Timothy Beyrle			Utilities Commission of New Smyrna Beach	FRCC					4				
2. Greg Woessner			Kissimmee Utility Authority	FRCC					1				
3. Jim Howard			Lakeland Electric	FRCC					1				
4. Lynne Mila			City of Clewiston	FRCC					3				
5. Joe Stonecipher			Beaches Energy Services	FRCC					1				
6. Cairo Vanegas			Fort Pierce Utility Authority	FRCC					4				
9.	Individual	Stephen Mizelle	Southern Company Transmission	X									
10.	Individual	Robert Casey	Georgia Transmission Corporation (Bulk System Planning)	X									
11.	Individual	Thad Ness	American Electric Power	X		X		X	X				
12.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
13.	Individual	Martin Bauer	US Bureau of Reclamation					X					
14.	Individual	Kirit Shah	Ameren	X		X		X	X				
15.	Individual	Robert W. Roddy	Dairyland Power Cooperative	X		X		X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
16.	Individual	Marty Berland	Progress Energy	X		X		X	X				
17.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
18.	Individual	Charles Lawrence	American Transmission Company	X									
19.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
20.	Individual	Bill Middaugh	Tri-State Generation and Transmission Association, Inc.	X		X		X	X				
21.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
22.	Individual	Dan Rochester	Independent Electricity System Operator		X								

1. **The SDT is proposing a revision to footnote 'b' in the TPL tables to comply with FERC Order RM-06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.**

Summary Consideration: The SDT has listened to the comments from the industry, understands the concerns raised, and has made changes to the footnote to balance the various industry concerns while assuring BES reliability.

The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. This is limited by two conditions: >90% demand level and 50 MW. The >90% demand level was selected to ensure that the number of hours with exposure to demand loss was not unlimited. A 90% demand level is a reasonably stressed case for most systems and the number of hours when peak demands are >90% is a small percentage of the time for most systems. A large percentage of the transmission lines that directly serve distribution customers are 161 kV or lower voltages. Ten percent (10%) of the demand on a high capacity 161 kV transmission line is approximately 50 MW.

A 4th bullet has also been added to clarify that it is acceptable to use Interruptible demand and Demand-Side Management.

To match the terminology in the revised footnote with the terminology in the associated column heading (Loss of Demand or Curtailed Firm Transfers) the term, 'Load' was replaced with 'Demand' and the term 'Firm Transmission Service' was replaced with 'firm transfers.'

Footnote 'b' now reads:

b)~~-~~No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Duke Energy	No	Duke Energy voted "Negative" on the initial and current ballots of TPL-001-1, primarily because Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We also sought rehearing on the Commission's March 18 Order Setting Deadline for Compliance (Docket No. RM06-16), with respect to this and other issues. We believe that FERC's directive in that Order to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the potential impacts (environmental, historical, archaeological, aesthetic...) of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. Duke offers the following ideas on alternatives for the SDT to consider that will allow for appropriate discretion and facilitate proper planning while allowing non-consequential load loss (NCLL).The standard should allow for dropping of limited amounts of non-consequential load in situations where it would be reasonable for a bounded time period and under restricted system conditions (e.g. 1-3 years only when load is >90 % of peak conditions). Dropping of non-consequential load would be prudent planning in situations where the near term impact of load projections or implementation of nearby transmission/generation projects will alleviate the necessity of an upgrade to meet N-1 conditions. Also, reliability of service to end-use customer is impacted by the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customers' level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to avoid projects without greatly impacting a customer's outage frequency

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>and duration should be acceptable. Use of reliability metrics (e.g. SAIFI/SAIDI/ASAI) should also be considered by the SDT for determination of acceptable use of NCLL.</td></tr>
<tr><td colspan="3">Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT discussed the use of reliability metrics for providing flexibility to planners but has not included their use as this would make the implementation too complex.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.</td></tr>
<tr><td>Midwest Reliability Organization</td><td>No</td><td>For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.</td></tr>
<tr><td>Dairyland Power Cooperative</td><td>No</td><td>DPC concurs with the MRO comments: For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.</td></tr>
<tr><td>American Transmission Company</td><td>No</td><td>For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		transmission system modifications.
Response: The SDT has added the fourth bullet to address your concern. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Georgia Transmission Corporation (Bulk System Planning)	No	Georgia Transmission Corporation (GTC) believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We believe that FERC's directive in (Docket No. RM06-16) to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view

Organization	Yes or No	Question 1 Comment
		to allow loss of non-consequential load.We also note that on April 19 NERC filed a request for rehearing with FERC asking that the Commission revise the directive in Paragraph 8 of the March 18 TPL-002 Order to allow NERC the necessary time to incorporate changes to the TPL-002 Reliability Standard through the Reliability Standards Development Process that are necessary to achieve bulk power system reliability. NERC also requested that the Commission grant NERC's Motion for Stay to stay the Order so that a public technical conference with opportunity for comment can be held in order to provide parties an opportunity to meet and discuss the technical considerations of developing a modification to the TPL-002 standard that prohibits the loss of non-consequential firm load in the event of an N-1 contingency. NERC's April 19 filing pointed out that if the Commission's directive to disallow the loss of non-consequential firm load for an N-1 contingency is implemented, a question is presented regarding whether the Reliability Standard still serves the purpose of ensuring the Reliable Operation of the bulk power system by preventing instability, uncontrolled separation, and cascading failures. That is, the Commission's directive sets forth an expectation that NERC is to implement standards that address all loss of load at costs that may not be commensurate with bulk power system reliability, as statutorily defined, which is fundamentally different from what the Reliability Standards were intended to do.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Progress Energy	No	Progress Energy applauds NERC's efforts to improve the footnote (b) language with respect to conditional allowance of curtailing Firm Transmission Service, which is addressed in the second paragraph of the proposed new footnote (b). PE remains concerned, however, that the first paragraph of the proposed new

Organization	Yes or No	Question 1 Comment
		footnote (b) does not allow for curtailment of non-radial non-consequential load. The ability to curtail non-consequential load in the planning horizon can be a useful tool to mitigate local area issues, and has not been detrimental to the Bulk Electric System (BES). Disallowing the curtailment of non-radial non-consequential load essentially prohibits taking action in situations in which the load in question is clearly at a localized self-contained level of the system, i.e. the distribution system(s) served by the Transmission Owner/Operator. Prohibiting the curtailment of local load thus constitutes regulating distribution feeder reliability rather than BES reliability. Events that could be mitigated through the curtailment of local, non-radial non-consequential load are infrequent, and such curtailment has no material effect on the reliability of the BES. PE therefore suggests that the following addition (item (3)) to the first paragraph of the proposed footnote (b) be considered:"No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, and/or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities, and/or (3) Planned or controlled interruption of any additional Load required to mitigate the post-contingency results, provided that the non-consequential load being shed for the event is localized, and provided that the total load shed for the event does not exceed 2% of the Planned system peak demand or 200 MW, whichever value is less."

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT did adopt a limit but felt that 2% of system peak or 200 MW was not equitable for all entities.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Hydro-Québec TransEnergie (HQT)	No	The proposed changes do not adequately address FERC's concerns in RM06-16-009. The Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." The proposed changes to footnote 'b' indicate "No interruption of firm Load is allowed except:... (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities." The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as "the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency." In referencing Order 693, the Commission reiterated its position that TPL standards "should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." "Must" should be used instead of "should" in the last sentence of the footnote, making it to read "Facility Ratings in those regions must also be respected."
Northeast Power Coordinating Council	No	The proposed changes do not adequately address FERC's concerns in RM06-16-009. The Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." The proposed changes to footnote 'b' indicate "No interruption of firm Load is allowed except:... (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities." The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as "the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency." In referencing Order 693, the Commission reiterated its position that TPL standards "should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." "Must" should be used instead of "should" in the last sentence of the footnote, making it to read "Facility Ratings in those regions must also be respected."
Response: The SDT believes that it has been responsive to the FERC directive in that the standards development process has been employed. In the		

Organization	Yes or No	Question 1 Comment
development of the footnote, the SDT has balanced the need for discretion while addressing local area concerns with the need to assure the reliability of the BES. 'Must' is not appropriate in a footnote as it would impose a requirement in the footnote. The SDT has replaced 'should' with 'would' to correct the grammar. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Tri-State Generation and Transmission Association, Inc.	No	Tri-State does believe that the new footnote is an improvement, but thinks there are still some changes necessary. We believe that the word "only" should be removed from the phrase "...where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities" because that discrimination was not required in FERC Order RM-06-16-009. There may be times when facilities near the temporary radial facilities might also fall outside the limits set in reliability criteria but the situation is mitigated if the load shedding occurs at the radial facility. The meaning of the second paragraph of the new footnote is unclear. Tri-State recommends changing it to "Curtailment of Firm Transmission Service is not allowed unless it is coupled with curtailment-offsetting resources that are obligated to re-dispatch. Further, the curtailment activities cannot result in the shedding of any Firm load or in violations of Facility Ratings, either internal or external to the planning region."
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. Instead of removing the word 'only', the 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:		

Organization	Yes or No	Question 1 Comment
		o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Southern Company Transmission	No	We propose that the section in double parentheses be deleted. The proposed wording by the drafting team seems to imply that the curtailment of firm transmission service is permitted to address single contingency constraints if coupled with the redispatch of network resources. The original language stated only that curtailments were permitted to prepare for the next contingency, not to address loading related to the initial contingency. The proposed wording could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint. Southern Companies recommend that the original language relating to "preparing for the next contingency" be incorporated into the drafting team's proposal.((Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.)) No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch. where it can It must be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

Organization	Yes or No	Question 1 Comment
Response: The SDT believes that System re-dispatch is an acceptable System adjustment to “remain within applicable Facility Ratings” to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote ‘b’ clarifies that re-dispatch is allowable to “remain within” ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can be only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the Firm Transmission Service cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words “To prepare for the next Contingency” to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch do~~es~~ not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
South Carolina Electric & Gas	Yes	For better clarity delete the phrase “when coupled with” in the second paragraph of footnote ‘b.’
Response: The SDT did not delete the suggested phrase as it believes it is correct as stated but added commas to make the phrase read more clearly. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~		

Organization	Yes or No	Question 1 Comment
o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Independent Electricity System Operator	Yes	IESO supports the revisions made to footnote 'b' based on the present definitions of BES and Firm Demand and on the understanding that the NERC standards apply only to the BES as defined in the NERC Glossary as follows:"As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." To be clear, our interpretation of the present definition of BES is that it defers to each Regional Reliability Organization to define the elements of the power system that are considered BES and, therefore in the NPCC Region, "BES as defined by NERC" = "BPS as defined by NPCC".
Response: The SDT agrees that the standard applies to the BES as defined in the Glossary.		
BPA, Transmission Reliability Program	Yes	On the firm transfer issues, the term "Firm Transmission Service" should be replaced with "Firm Transfers" to be consistent with the fourth column of the existing Table 1 Transmission System Standards - Normal and Emergency Conditions.
Response: The SDT agrees and has made the change. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW		

Organization	Yes or No	Question 1 Comment
o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
American Electric Power	Yes	
Exelon Transmission Strategy & Compliance	Yes	
Florida Municipal Power Agency	Yes	
IESO	Yes	
Northeast Utilities	Yes	
Pepco Holdings, Inc.	Yes	
US Bureau of Reclamation	Yes	
Manitoba Hydro	Yes	MH agrees with the SDT proposal.
Ameren	Yes	We were ok with the previous language. Though we do not intend to drop non-consequential load for a single contingency, we undersatnd that other ares may have been following such practice without degarding the relaibility of BES. We believe that they can continue this practice if they develop non-firm contracts with these customers.
Response: Thank you for your support.		

2. Are you aware of any conflicts caused by compliance with the proposed language in Table 1 — footnote b and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement? If yes, please identify the conflict.

Summary Consideration: The SDT understands that there may be conflicts as pointed out by respondents; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.

b)~~–~~No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 2 Comment
Ameren	No	
American Electric Power	No	
American Transmission Company	No	
BPA, Transmission Reliability	No	

Organization	Yes or No	Question 2 Comment
Program		
Dairyland Power Cooperative	No	
Exelon Transmission Strategy & Compliance	No	
Independent Electricity System Operator	No	
Manitoba Hydro	No	
Midwest Reliability Organization	No	
Southern Company Transmission	No	
US Bureau of Reclamation	No	
South Carolina Electric & Gas	No	The comments expressed herein represent a consensus of the views of the above named members of the SERC Engineering Committee Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.
Response: Thank you for your response.		
Hydro-Québec TransEnergie (HQT)	Yes	Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.
Northeast Power Coordinating Council	Yes	Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.

Organization	Yes or No	Question 2 Comment
IESO	Yes	It should be noted that conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. In RM-06-16-009, the Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." In the US, State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.Similar conflicts may also exist in Canada.
Progress Energy	Yes	There is the potential for conflict between Table 1 - Footnote (b) as currently proposed, which can be considered to regulate local distribution reliability without improving BES reliability, and local service reliability issues which are under the purview of state regulatory agencies. For example, the North Carolina Utilities Commission (NCUC) commented regarding this concern in the ballot which ended March 1 in Project 2006-02. Specifically, NCUC commented that they were "...concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1 is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions..." Progress Energy believes that NCUC's concerns are legitimate. BES reliability should address the avoidance and mitigation of cascading outages and BES facility damage, rather than limited, controlled local area loss of load, in order to avoid this conflict and overlap of regulation.
Response: The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.		
Northeast Utilities	Yes	Northeast Utilities (NU) believes the language of the proposed revision to footnote 'b' can be better defined as the proposed revision is subject to interpretation by the different entities and regulatory agencies. Future conflicts can be minimized by further clarifying the proposed revision. Also, NU is concerned that this new modification does not specify the amount of permissible load shed nor does it require the planning entity to minimize load shedding under this exception.
Response: The SDT has made several clarifying changes to the footnote which should alleviate your concerns. The SDT has modified the footnote for clarity and added constraints in new bullet 3 to address your specific concern.		

Organization	Yes or No	Question 2 Comment
b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Duke Energy	Yes	See response to question #1.
Georgia Transmission Corporation (Bulk System Planning)	Yes	See response to Question #1.
Response: See response to question #1.		
Florida Municipal Power Agency	Yes	This is an area of fuzziness between State jurisdiction and Federal jurisdiction. In all honesty, shedding load for local area impacts has nothing to do with BES reliability and should not be under FERC jurisdiction under Section 215 of the Federal Power Act, but rather State jurisdiction for quality of service issues. However, there is also the matter of FERC jurisdiction over commercial matters and the opportunity to "game" the original footnote by transmission providers by allowing firm load shedding to grant firm transmission service for themselves, thereby avoiding or deferring transmission investment, while at the same time denying or requiring others to build the same transmission avoided in order to obtain transmission service. We can see how difficult it is from a drafting team's perspective in achieving a balanced position between these different matters. The drafting team should be applauded for finding a reasonable position.
Pepco Holdings, Inc.	Yes	This is not an issue for historic PJM members, but as PJM has expanded and as a result of the merger of historic councils into RFC, I am aware that not all regions had standards equal to those of MAAC, and this

Organization	Yes or No	Question 2 Comment
		has been an issue worked out between transmission planners (historic transmission owners) and their local regulators. It is ultimately a cost issue for loss of local load that does not affect the overall reliability of the interconnected BES.
Response: Thank you for your support.		
Tri-State Generation and Transmission Association, Inc.	Yes	We believe that FERC's directive in FERC Order RM-06-16-009 to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load.
Response: The SDT is not in a position to comment on FERC's authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.		

3. Consideration of Comments on Initial Ballot — TPL Table 1 Order (Project 2010-11) May 17–27, 2010

Summary Consideration: The SDT has listened to the comments from the industry, understands the concerns raised, and has made changes to the footnote to balance the various industry concerns while assuring BES reliability.

The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. This is limited by two conditions: >90% demand level and 50 MW. The >90% demand level was selected to ensure that the number of hours with exposure to demand loss was not unlimited. A 90% demand level is a reasonably stressed case for most systems and the number of hours when peak demands are >90% is a small percentage of the time for most systems. A large percentage of the transmission lines that directly serve distribution customers are 161 kV or lower voltages. Ten percent (10%) of the demand on a high capacity 161 kV transmission line is approximately 50 MW.

A 4th bullet has also been added to clarify that it is acceptable to use Interruptible demand and Demand-Side Management.

The second paragraph of the footnote has been clarified and references Firm Transfers now instead of Firm Transmission Service.

b) No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Rodney Phillips	Allegheny Power	1	Negative	Allegheny Power believes the loss of non-consequential load and/or curtailment of transmission service for N-1 contingencies should be limited to only extreme circumstances. Exception 2 of footnote b allows for the loss of non-consequential load for N-1

Voter	Entity	Segment	Vote	Comment
				contingencies with no restriction. Allegheny Power recommends removing exception 2 footnote b.
Response: The SDT and the majority of the commenters disagree with this suggestion.				
Gordon Rawlings	BC Transmission Corporation	1	Negative	BCTC appreciates the good work of the SAR committee in drafting the changes to Footnote b of Table 1. BCTC agrees with the drafting team that interruption of firm load, served by either radial circuits or circuits that have became radial as a result of the contingency, should be allowed for N-1 contingencies. However, it is our position that interruption of firm load should not be limited only to such consequential loads. In our view, interruption of electric supply to some local network customers in the affected area should be permissible. This inclusion will allow transmission planners to plan BCTC's regional transmission network reliably and without impacting neighbouring transmission networks.
Faramarz Amjadi	BC Transmission Corporation	2	Negative	
Hubert C. Young	South Carolina Electric & Gas Co.	3	Negative	SCE&G has significant concern with the proposed revision to TPL Table 1, Footnote B. The current Footnote B states "Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems". The phrase "without impacting the overall reliability of the interconnected transmission systems" is important to the TPL standards to ensure that ERO standards do not dictate the level of service to customers. Service to customers and load pockets is jurisdictional to State Commissions and ERO standards should not compromise this jurisdiction. SCE&G believes that any proposed revisions to Footnote B must retain the concept that planned or controlled interruption of electric supply to customers, whether they are radial or network, is allowed as long as it does not impact the overall reliability of the interconnected transmission systems. The proposed revision eliminates this concept. There seems to be a general inconsistency and maybe confusion between the terms "reliability" and "level of service".
David Frank Ronk	Consumers Energy	4	Negative	The current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the previous version of TPL-001-1. However, it still does not allow Transmission Planners to use appropriate and necessary discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should control the decision making when BES reliability is not an issue. Often, the consequences of these events are solely local in nature, requiring only minor additional loss of local load to
James B Lewis	Consumers Energy	5	Negative	

Voter	Entity	Segment	Vote	Comment
				avoid the costly major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load.
Hugh A. Owen	Public Utility District No. 1 of Chelan County	6	Negative	The interruption of a small amount of load is, under most conditions, not a risk to the reliability of the BES and is at times necessary to preserve reliability. The planned interruption of some load may be a cost effective alternative to a costly transmission project. That is a quality of service issue.
Michael Gammon	Kansas City Power & Light Co.	1	Negative	While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load.
Charles Locke	Kansas City Power & Light Co.	3	Negative	
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	
Linda Brown	San Diego Gas & Electric	1	Affirmative	As to item (1), all load served directly by a transmission element which experiences a fault will be interrupted when the faulted element is taken out of service. This is the natural relationship between the load and the transmission element. Allowing this for BES elements may encourage transmission owners to remove transmission instead of upgrading or replacing it. Consider a load supplied by two transmission lines of different capacity. If the larger line is lost due to a contingency (N-1) and the remaining smaller line overloads the transmission owner is left with several options to address the problem: (1) move load between buses, (2) upgrade the smaller line, (3) add another line, or (4) create a radial load by removing the smaller line. Number (4) may be the least expensive and allowable under TPL-002, footnote b. Item (2) may also encourage transmission owners to develop plans which make load shedding part of category B. Consider a load served by three transmission lines, a utility may decide to remove a line, instead of upgrading, in order to set up a situation where an N-1 contingency would make the bus temporarily radial. In the event of a single outage (N-1), the load bus will be temporarily radial and load can be shed at the bus.

Voter	Entity	Segment	Vote	Comment
W. R. Schoneck	Florida Power & Light Co.	3	Affirmative	I believe the language is an improvement and clarifies the intent but I believe there still should be additional language added to give an exemption in meeting this requirement if it does not make economic sense(not economically feasible) and has no real impact on the BES.
Richard J Kafka	Potomac Electric Power Co.	1	Affirmative	It is understood that this is a compliance filing issue. This is not an issue for historic PJM members, but as PJM has expanded and as a result of the merger of historic councils into RFC, I am aware that not all regions had standards equal to those of MAAC, and this has been an issue worked out between transmission planners (historic transmission owners) and their local regulators. It is ultimately a cost issue for loss of local load that does not affect the overall reliability of the interconnected BES.
Alan Gale	City of Tallahassee	5	Affirmative	TAL thanks for SDT for the tireless effort to get to this point. TAL is voting affirmative with the following comments. We accept that the loss of non-consequential load is not a desired result for N-1 contingencies. It is also not the norm in system planning or operations. The flexibility to operate the system consistent with “good utility practice” may warrant the “odd-ball” case that would require this to occur. The dropping of non-consequential load will NOT lead to BES instability, voltage collapse, or cascading outages, which is what FERC and NERC are charged with preventing. It will lead to the shedding of load in a local area only. Utilities do not drop customers lightly. If the meter isn’t turning, we are not getting paid, so we want the meter spinning. Utility power, while vital to our normal day-to-day lives and infrastructure, was never intended to be without interruption.
Brad Chase	Orlando Utilities Commission	1	Affirmative	This change raises the bar on transmission system performance. This change applies a blanket requirement upon entities that does not take into account the number of outages, probability of outages or cost to the customer. There are certain to be situations where this blanket requirement will result in increased cost to customers for no noticeable increase in reliability. OUC does agree with the concept of greater clarification on this requirement, however this clarification may raise the bar to far by trying to establish a blanket requirement. Duke, Progress Energy and others will be submitting comments with proposed language that attempt to address some of these issues and we encourage the drafting team to consider those comments.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate				

Voter	Entity	Segment	Vote	Comment
constraints. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
Eric Egge	Black Hills Corp	1	Negative	Black Hills believes that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td>Chifong L. Thomas</td><td>Pacific Gas and Electric Company</td><td>1</td><td>Negative</td><td>PG&E commends the SDT for developing the proposed footnote b. While it is a great improvement over the complete prohibition on loss of non-consequential load for any single contingency, the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system, especially where the impact is local in nature, to avoid instability, cascading or uncontrolled separation. Such planned interruption of load may be a reasonable alternative to the environmental impacts or prohibitive costs associated with a major new transmission project. Given the potential impacts of the proposed modification, further vetting of the issues is needed. PG&E believes that NERC should be allowed to hold a public technical conference, as described in NERC’s April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.</td></tr>
<tr><td>Thomas J. Bradish</td><td>RRI Energy</td><td>5</td><td>Negative</td><td rowspan="2">RRI supports the WECC position on this issue; namely, that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC’s April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.</td></tr>
<tr><td>Trent Carlson</td><td>RRI Energy</td><td>6</td><td>Negative</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
John Tolo	Tucson Electric Power Co.	1	Negative	The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project.
James Tucker	Deseret Power	1	Negative	The prohibition of loss of non-consequential load for events resulting the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Louise McCarren	Western Electricity Coordinating Council	10	Negative	The proposed revisions to footnote b of Table 1 are an improvement to the recently balloted prohibition on loss of non-consequential load for single contingencies. The recognition of the new term "temporarily radial" is a step in the right direction. However, the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their

Voter	Entity	Segment	Vote	Comment
				individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
William Mitchell Chamberlain	California Energy Commission	9	Negative	While the proposed revisions to footnote b are an improvement to the prohibition on loss of non-consequential load for a single contingency proposed in the recently failed TPL-001-1 ballot, the prohibition of loss of non-consequential load for events resulting the loss of a single element still inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
John Mick	Colorado Springs Utilities	6	Negative	Colorado Springs Utilities ballot on the proposed changes to TPL Table 1, footnote b directed in FERC Order RM06-16-009 Colorado Springs Utilities wishes to vote NO on the proposed changes to TPL Table 1, footnote b, directed in FERC Order RM06-16-009. CSU concurs with the WECC position paper for the ballot, and agrees with the WECC statement "that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues".

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td colspan="5">The SDT agrees that a technical conference on this issue would be of value.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

o (1) ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~

o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~

o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW

o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.</td></tr>
<tr><td>Horace Stephen Williamson</td><td>Southern Company Services, Inc.</td><td>1</td><td>Negative</td><td rowspan="3">Comments have already been submitted previously, but it will be added here again. Proposed footnote should read... No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers when coupled with the appropriate re-dispatch of resources obligated to re-dispatch. It must be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. The proposed changes are based on the</td></tr>
<tr><td>Richard J. Mandes</td><td>Alabama Power Company</td><td>3</td><td>Negative</td></tr>
<tr><td>Anthony L Wilson</td><td>Georgia Power Company</td><td>3</td><td>Negative</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
Gwen S Frazier	Gulf Power Company	3	Negative	following... "The proposed wording by the drafting team seems to imply that the curtailment of firm transmission service is permitted to address single contingency constraints if coupled with the redispatch of network resources. The original language stated only that curtailments were permitted to prepare for the next contingency, not to address loading related to the initial contingency. The proposed wording could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint. Southern Companies recommend that the original language relating to "preparing for the next contingency" be incorporated into the drafting team's proposal."
Don Horsley	Mississippi Power	3	Negative	
Michael Ibold	Xcel Energy, Inc.	3	Negative	The proposed modification to footnote b of Table I in TPL-001 - 004 standards states that after a Category B contingency, there should not be any thermal, voltage or stability violation, no interruption of firm load (except the load that is directly connected to the elements that are removed from service as a result of the contingency) and no firm transfer curtailment (except when coupled with re-dispatch of resources obligated to re-dispatch). We believe the proposed footnote b creates a gap between TPL-002 and TPL-003 standards, since it does not address conditions when firm load shedding and firm transfer curtailments are not required to meet the system performance for Category B contingency, but one or both are the required system adjustments to prepare for the next contingency (Category C3). When firm transfer is curtailed after the first contingency in preparation for the next contingency, it is not clear from the proposed footnote b if this is considered a valid system adjustment for Category C or a violation of Category B. Recall that the existing footnote b addresses this condition explicitly by stating "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm Transfers."
Liam Noailles	Xcel Energy, Inc.	5	Negative	
David F. Lemmons	Xcel Energy, Inc.	6	Negative	
George T. Ballew	Tennessee Valley Authority	5	Affirmative	TVA appreciates the work of the SDT on this issue. However, TVA recommends revising the second paragraph of the revised footnote b: "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. However, curtailment of Firm Transmission Service is only allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility
Marjorie S. Parsons	Tennessee Valley Authority	6	Affirmative	

Voter	Entity	Segment	Vote	Comment
				Ratings in those regions should also be respected." Without the changes in the first two sentences above, the proposed wording by the SDT could be interpreted to allow re-dispatch/firm curtailments to address any single contingency constraint instead of in preparation for the next contingency.
Larry Akens	Tennessee Valley Authority	1	Affirmative	TVA appreciates the work of the SDT. However, TVA recommends revising the second paragraph of the revised footnote "b". Without changes in the first two sentences, the proposed wording by the SDT could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint instead of in preparation for the next contingency.

Response: The SDT believes that System re-dispatch is an acceptable System adjustment to "remain within applicable Facility Ratings" to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can be only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the Firm Transmission Service cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Robert W. Roddy	Dairyland Power Coop.	1	Negative	DPC CONCURS WITH THE MRO COMMENTS.
Jason Shaver	American Transmission Company, LLC	1	Affirmative	For Footnote b, add a third exception to the list, “or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed if the tripping of the load is either accepted or volunteered by the customer.
Lawrence R. Larson	Otter Tail Power Company	1	Negative	The change precludes the use of direct load control systems that should be allowed to relieve transmission problems. These systems control firm transmission load but rate conditions can allow their use to mitigate transmission problems.

Response: *(Note - MRO did not submit comments with the initial ballot – but did submit the following comment during the formal comment period: For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.)*

The SDT has added the fourth bullet to address your concern.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
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Voter	Entity	Segment	Vote	Comment
Ajay Garg	Hydro One Networks, Inc.	1	Negative	Hydro One is casting a negative vote for the following reasons: 1. The amendment to the footnote does not add any technical value to the standard. It was added only to satisfy a FERC directive to address comments made to allow non-consequential load loss after a single contingency event, “based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios.” 2. Addressing curtailment of Firm Transmission Service with re-dispatch of resources is a matter of a commercial nature and should be dealt with in the agreements dealing with such services. Issues of contracted transmission services, firm or otherwise, are not a reliability related matter and are not to be dealt with in this standard. 3. Matters of interruption of firm load should be incorporated into this standard only after the FERC NOPR on the definition of the BES is resolved. As it stands, the footnote will pose significant problems if the 100 kV and above FERC proposal is applied across the board, unless the standard specifically states that it applies to the BES as defined by the region (current definition).
Michael D. Penstone	Hydro One Networks, Inc.	3	Negative	
Response: 1. & 2. The SDT disagrees – there is a direct impact on reliability of the BES associated with these concerns. The SDT has added clarity to the footnote by designating constraints for Demand and firm transfer curtailment. 3. The SDT disagrees that this needs to wait on the FERC NOPR. This standard is applicable to the BES as it is defined.				
Spencer Tacke	Modesto Irrigation District	4	Negative	I am voting NO vote because of the lack of clarity of the second paragraph of the proposed change. Although paragraph 1 is an improvement to the current wording, and actually allows for some specific flexibility in shedding load for an N-1 event, the lack of clarity in the second paragraph could lead to varied interpretations by members and compliance auditors. Thank you.
Response: The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:				

Voter	Entity	Segment	Vote	Comment
				o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Dana Cabbell	Southern California Edison Co.	1	Negative	It is SCE's position that the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. When planned load interruption is identified as a response to a single event, the impact to the system is often local in nature. The planned interruption of load may be a desirable alternative to the prohibitive costs associated with a major new transmission project. If the NERC Standards Drafting Team decides to proceed with footnote B, as written, it needs to ensure that Transmission Owners, Transmission Operators, and Transmission Planners have enough time to both design and implement any mitigation plans necessary to be compliant with the new language. In almost all cases the actual implementation of a solution requiring new construction will be dependent on a number of different regulatory agencies providing the necessary permits allowing for its construction. As such, NERC needs to ensure that any time frame associated with compliance to the proposed language be variable, and allow for extended implementation time frames based on system conditions that may delay placing mitigation plans in service. An example of a reasonable variable time frame to be compliant with the proposed language in footnote B would be to start the clock 60 months from receiving the pertinent environmental permitting. In
David Schiada	Southern California Edison Co.	3	Negative	
Ahmad Sanati	South California Edison Company	5	Negative	

Voter	Entity	Segment	Vote	Comment
				California this could be the issuance of a Draft Environmental Impact Review pursuant to the California Environmental Quality Act.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

The SDT has added more latitude for the Transmission Planner with the addition of the 3rd bullet and believes that 60 months should be sufficient.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Henry Ernst-Jr	Duke Energy Carolina	3	Negative	On the initial ballot of TPL-001-1 Duke Energy also voted "Negative", primarily because Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We also sought rehearing on the Commission's March 18 Order Setting Deadline for Compliance (Docket No. RM06-16), with respect to this and other issues. We believe that FERC's directive in that Order to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the potential impacts (environmental, historical, archaeological, aesthetic...) of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. With this "Negative" vote, Duke offers the following ideas on alternatives for the SDT to consider that will allow for appropriate discretion and facilitate proper planning while allowing non-consequential load loss (NCLL). The standard should allow for dropping of limited amounts of non-consequential load in situations where it would be reasonable for a bounded time period and under restricted system conditions (e.g. 1-3 years only when load is >90 % of peak conditions). Dropping of non-consequential load would be prudent planning in situations where the near term impact of load projections or implementation of nearby transmission/generation projects will alleviate the necessity of an upgrade to meet N-1 conditions. Also, reliability of service to end-use customer is impacted by the entire system

Voter	Entity	Segment	Vote	Comment
				from source to load. Where allowance for NCLL would not greatly impact individual end-use customers' level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to avoid projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics (e.g. SAIFI/SAIDI/ASAI) should also be considered by the SDT for determination of acceptable use of NCLL.
Luther E. Fair	Gainesville Regional Utilities	1	Affirmative	Even though I am voting in the affirmative, I agree that most of the comments offered by Duke and Norther Indiana in their earlier statements have merit and should be considered. Also, I believe that the use of reliability metrics should be considered by the SDT for determination of acceptable use of NCLL.
Mace Hunter	Lakeland Electric	3	Negative	Reliability should consider the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customer's level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to delay projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics should also be considered by the SDT for determination of acceptable use of NCLL.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

The SDT discussed the use of reliability metrics for providing flexibility to planners but has not included their use as this would make the implementation too complex.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

Voter	Entity	Segment	Vote	Comment
				o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Sammy Roberts	Progress Energy Carolinas	1	Negative	Progress Energy applauds NERC's efforts to improve the footnote (b) language with respect to conditional allowance of curtailing Firm Transmission Service, which is addressed in the second paragraph of the proposed new footnote (b). PE remains concerned, however, that the first paragraph of the proposed new footnote (b) does not allow for curtailment of non-radial non-consequential load. The ability to curtail non-consequential load in the planning horizon can be a useful tool to mitigate local area issues, and has not been detrimental to the Bulk Electric System (BES). Disallowing the curtailment of non-radial non-consequential load essentially prohibits taking action in situations in which the load in question is clearly at a localized self-contained level of the system, i.e. the distribution system(s) served by the Transmission Owner. Prohibiting the curtailment of local load thus constitutes regulating distribution feeder reliability rather than BES reliability. Events that could be mitigated through the curtailment of local, non-radial non-consequential load are infrequent, and such curtailment has no material effect on the reliability of the BES. PE therefore suggests that the following addition (item (3)) to the first paragraph of the proposed footnote (b) be considered: "No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, and/or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities, and/or (3) Planned or controlled interruption of any additional Load required to mitigate the post-contingency results, provided that the non-
Lee Schuster	Florida Power Corporation	3	Negative	
Sam Waters	Progress Energy Carolinas	3	Negative	
Wayne	Progress Energy	5	Negative	

Voter	Entity	Segment	Vote	Comment
Lewis	Carolinas			consequential load being shed for the event is localized, and provided that the total load shed for the event does not exceed 2% of the Planned system peak demand or 200 MW, whichever value is less.”

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT did adopt a limit but felt that 2% of system peak or 200 MW was not equitable for all entities.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Timothy VanBlaricom	California ISO	2	Negative	The California ISO supports NERC’s request for a public technical conference to be held, as described in NERC’s April 19, 2010 request for rehearing and motion for stay of the March 18 Order (RM06-16-009), to provide the opportunity to gain industry input and written comments regarding the Commission’s TPL-002-0 directive for NERC to develop a modification to the TPL-002-0 Table 1 footnote b.

Response: The SDT agrees that a technical conference would be of value.

Voter	Entity	Segment	Vote	Comment
Terry L. Blackwell	Santee Cooper	1	Negative	The Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning processes appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. Table B footnote still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, and local customers should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. The Commission's directive sets forth an expectation that NERC is to implement standards that address all loss of load at costs that may not be commensurate with bulk power system reliability, as statutorily defined, which is fundamentally different from what the Reliability Standards were intended to do.
Zack Dusenbury	Santee Cooper	3	Negative	
Suzanne Ritter	Santee Cooper	6	Negative	
Response: The SDT is not in position to comment on FERC's authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.				
Kimberly J. Jones	North Carolina Utilities Commission	9	Negative	The NC Utilities Commission is concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1, and as explained in draft footnote b, is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions. This requirement does not provide any benefit to reliability of the bulk electric system and could undermine state efforts to balance reliability issues with cost of service issues. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load, understanding that state commissions are positioned to force electric utilities to address local service quality issues on an expedited basis, should it be necessary and in the public interest.
Response: The SDT understands the concern but believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.				

Voter	Entity	Segment	Vote	Comment
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Negative	THE PROPOSED INTERPRETATION WILL UNDERMINE THE INTERNATIONAL STANDARDS SETTING PROCESS AND COULD RESULT IN DIFFERING INTERPRETATIONS OF STANDARDS ON THE NORTH AMERICAN BULK-POWER SYSTEM.
Response: The SDT disagrees and believes that the footnote has been clarified appropriately within the standards development process.				
Daryn Barker	Louisville Gas and Electric Co.	6	Negative	The revised footnote b on Table 1 imposes additional requirements on the responsible entities. The footnote states: Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. However, R1 states: The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned These statements address different and inconsistent scope. If the change in scope was intended then a change should also be made to R1 to reconcile the inconsistency.
Charlie Martin	Louisville Gas and Electric Co.	5	Negative	Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. However, R1 states: The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned These statements address different and inconsistent scope. If the change in scope was intended then a change should also be made to R1 to reconcile the inconsistency.
Response: The SDT agrees that your assessment is for your portion of the interconnected grid. However, when performance in one system is dependent on generation dispatch in another system or vice versa, the SDT believes that one must ensure that the re-dispatch is feasible. The SDT does not believe that this presents a conflict with Requirement R1.				
John Apperson	PacifiCorp	3	Negative	This proposal warrants a "no" vote due to the current uncertainty regarding the outcome of the FERC TPL-002 NOPR issued by FERC on March 18, 2010. The impacts of the proposed changes to footnote B cannot be assessed separately from the alternative interpretation of TPL-002 proposed by FERC. The proper planning of a transmission system requires that all performance requirements are known and understood. If only some of the requirements are known and understood it is impossible to properly plan, study, assess, and operate the transmission system.

Voter	Entity	Segment	Vote	Comment
Response: The current TPL-002 is in force and will remain so until the completion of the cited FERC NOPR. This limited scope revision to footnote 'b' is to add clarity to what is in effect.				
Keith V. Carman	Tri-State G & T Association Inc.	1	Negative	Tri-State does believe that the new footnote is an improvement, but thinks there are still some changes necessary. We believe that the word "only" should be removed from the phrase "...where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities" because that discrimination was not required in FERC Order RM-06-16-009. There may be times when facilities near the temporary radial facilities might fall outside the limits set in reliability criteria but the situation is mitigated if the load shedding occurs at the radial facility. The meaning of the second paragraph of the new footnote is unclear. Tri-State recommends changing it to "Curtailment of Firm Transmission Service is not allowed unless it is coupled with curtailment-offsetting resources that are obligated to re-dispatch. Further, the curtailment activities cannot result in the shedding of any Firm load or in violations of Facility Ratings, either internal or external to the planning region." We believe that FERC's directive in FERC Order RM-06-16-009 to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. Instead of removing the word 'only', the 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.				

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b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected. The SDT is not in position to comment on FERC's authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.				
Claudiu Cadar	GDS Associates, Inc.	1	Negative	We do not agree with the proposed changes due to several reasons. Although the proposed change will directly influence the reliability standards and transmission system performances, will also have an indirect impact on the economic side with respect to the expansion of existing transmission system. We believe that FERC directive as stipulated in Order 693 cannot constrict, nor impose certain actions outside of the reliability limits. We believe that since these events are merely isolated and rarely enforced, the decision of mandating a great financial effort as a consequence of the proposed changes would certainly be counterbalanced by its feasibility when compare with the current cost of load shedding. While the revised footnote b can be certainly considered an improvement from the current version, however it still does not allow the joined entities involved to have power over the decision making when BES reliability is not an issue. We also believe that any mandatory changes implemented in the TPL standards under the current scenario are not entirely feasible unless all other issues such as the definition of the

Voter	Entity	Segment	Vote	Comment
				BES, Consequential / Non-consequential Load, BES Critical Element, etc gets resolve ahead. The revision with respect to load shedding, specifically the portion about shedding loads on newly radial facilities, does not match the version 1 TPL standard definition of consequential load loss. To approve the proposed revision to footnote 'b' would create an unnecessary discrepancy between the version 1 TPL standard under consideration and the existing standards. We recognize that the Version 1 will replace Version 0, but since it appears that the performance standard with respect to footnote 'b' is intended to be same in the revised footnote and the Version 1 standard, it only makes sense that the revised version 0 footnote 'b' match the consequential load loss definition contemplated in Version 1. In the light of the above we suggest the Commission to approach different other solutions and ideas for improving the current reliability of the transmission system without enforcing decisions beyond its statutory scope. We advance an alternative to this matter meant to balance the reliability of the transmission system and its indirect financial impact. Although the solution that we offer would require an extended time for development and implementation, however we urge NERC to consider it in its further approach. Our alternative consists mainly in implementing an additional term such as "Critical Load" which we have briefly figured that would consist in particular load necessary to be maintained in service without interruption. Even though this new term would seemed to be at first related with the quality of the service, however a joint association of transmission planners, customers, regulatory entities as decision makers can simply individualize the load that cannot be shed, as well as future transmission improvements that will be required to serve this envisioned small amount of load rather than the entire load. In this way we will create a reasonable balance in between the reliability of the transmission system and the cost to maintain / improve this reliability.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~

Voter	Entity	Segment	Vote	Comment
				o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected. The current TPL-002 is in force and will remain so for the forseeable future. This limited scope revision to footnote 'b' is to add clarity to what is in effect. Project 2006-02 is under revision and the clarifications of footnote 'b' will be considered by the SDT for future revisions of TPL-001-2. The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.
Ronald D. Schellberg	Idaho Power Company	1	Negative	While the proposed revisions are an improvement to the prohibition on loss of non-consequential load for a single contingency proposed in the recently failed TPL-001-1 ballot, that the prohibition of loss of non-consequential load for events resulting the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. However, the removal of: "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." will require significant adjustments in either TRM or TTC reductions to be compliant with this revised standard in the WECC Region. To construct additional transmission facilities to maintain present day business could easily exceed 10 Billion dollars throughout the WECC region. For example, the Pacific AC Intertie currently has a TTC of 4800 MW spread across 3 500 kV transmission lines. With the loss of one Transmission line, the Pacific AC intertie drops to 3200 MW. Removal of this sentence would require TP either to drop the Firm TTC of the Intertie to 3200, or include a TRM reservation of at least 1600 MW. The TPs would not be able to say that a loss of 1600 MW of import capacity would not result in curtailments of firm load. Just about all multi

Voter	Entity	Segment	Vote	Comment
				transmission line paths in the WECC Region would suffer. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. In the case of long interties between subregions of WECC, these interties have never been planned to operate in this manner. Idaho Power recommends that the sentence permiting system adjustments be reinserted into Footnote B.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

The SDT believes that System re-dispatch is an acceptable System adjustment to "remain within applicable Facility Ratings" to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can be only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the Firm Transmission Service cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW

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o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
Francis J. Halpin	Bonneville Power Administration	5	Affirmative	For consistency, regarding the firm transfer issue, the term "Firm Transmission Service" should be replaced with "Firm Transfers" in order to be consistent with the fourth column of the existing Table 1 "Transmission System Standards - Normal and Emergency Conditions".
Response: The SDT agrees and has made the change. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
Kim Warren	Independent Electricity System Operator	2	Affirmative	IESO supports the revisions made to footnote 'b' based on the present definitions of BES and Firm Demand and on the understanding that the NERC standards apply only to the BES as defined in the NERC Glossary as follows: "As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighbouring systems, and associated equipment, generally operated at voltages of 100 kV

Voter	Entity	Segment	Vote	Comment
				or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." To be clear, our interpretation of the present definition of BES is that it defers to each Regional Reliability Organization to define the elements of the power system that are considered BES and, therefore in the NPCC Region, "BES as defined by NERC" = "BPS as defined by NPCC".
Response: The SDT agrees that the standard applies to the BES as defined in the Glossary.				
Jacquie Smith	ReliabilityFirst Corporation	10	Affirmative	If this revision is an urgent action, then the implementation timeframe should be shorter. In the clarification paragraph below, I do not understand the first sentence. Are there commas missing? What is the requirement and what is the exception? Also, I question the validity of using "should" in the second sentence. If it is a requirement, then it needs to be stated as a requirement. If it is a suggestion, then it does not belong in the standard. No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.
Response: This has not been classified as an 'urgent action'. Commas have been added as appropriate and a re-wording was made which should make this clear. 'Should' has been replaced by 'would' to provide additional clarity. b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels				

Voter	Entity	Segment	Vote	Comment
				greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
David H. Boguslawski	Northeast Utilities	1	Affirmative	Northeast Utilities (NU) believes the language of the proposed revision to footnote 'b' can be better defined as the proposed revision is subject to interpretation by the different entities and regulatory agencies. Future conflicts can be minimized by further clarifying the proposed revision. Also, NU is concerned that this new modification does not specify the amount of permissible load shed nor does it require the planning entity to minimize load shedding under this exception.

Response: The SDT has made several clarifying changes to the footnote which should alleviate your concerns.

The SDT has modified the footnote for clarity and added constraints in new bullet 3 to address your specific concern.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Donald S. Watkins	Bonneville Power Administration	1	Affirmative	On the firm transfer issues, the term "Firm Transmission Service" should be replaced with "Firm Transfers" to be consistent with the fourth column of the existing Table 1 Transmission System Standards - Normal and Emergency Conditions.
Rebecca Berdahl	Bonneville Power Administration	3	Affirmative	
Brenda S. Anderson	Bonneville Power Administration	6	Affirmative	

Response: The SDT agrees and has made this change.

b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- o Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Frank Gaffney	Florida Municipal Power Agency	4	Affirmative	Please see FMPA comments submitted through the concurrent comment period for Project 2010-11
David Schumann	Florida Municipal Power Agency	5	Affirmative	

Voter	Entity	Segment	Vote	Comment
Response: Please see the response to FMPA comments above.				
Carter B Edge	SERC Reliability Corporation	10	Affirmative	The footnote makes clearer when load can be dropped for planning purposes. By making this footnote more specific, it supports reliability and helps stakeholders apply the TPL standards.
Timothy Beyrle	City of New Smyrna Beach Utilities Commission	4	Affirmative	This is an area of fuzziness between State jurisdiction and Federal jurisdiction. In all honesty, shedding load for local area impacts has nothing to do with BES reliability and should not be under FERC jurisdiction under Section 215 of the Federal Power Act, but rather State jurisdiction for quality of service issues. However, there is also the matter of FERC jurisdiction over commercial matters and the opportunity to “game” the original footnote by transmission providers by allowing firm load shedding to grant firm transmission service for themselves, thereby avoiding or deferring transmission investment, while at the same time denying or requiring others to build the same transmission avoided in order to obtain transmission service. We can see how difficult it is from a drafting team’s perspective in achieving a balanced position between these different matters. The drafting team should be applauded for finding a reasonable position.
Response: Thank you for your support.				
Larry E Watt	Lakeland Electric	1	Affirmative	This issue is better handled within the development of the new TPL-001 standard.
Response: The current TPL-002 is in force and will remain so until the completion of the TPL-001-2 effort. This limited scope revision to footnote ‘b’ is to add clarity to what is in effect.				

Implementation Plan for Project 2010-11: TPL Table 1 Order

Prerequisite Approvals

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

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed standards.

Compliance with Standards

Standards	Functions That Must Comply With the Associated Requirements	
	Transmission Planner	Planning Authority
TPL-001-0.2: System Performance Under Normal (No Contingency) Conditions (Category A) TPL-002-0c: System Performance Following Loss of a Single Bulk Electric System Element (Category B) TPL-003-0b: System Performance Following Loss of Two or More Bulk Electric System Elements (Category C) TPL-004-0a: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

The effective date for footnote 'b' will be the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption.

All other requirements remain in effect as per previous approvals.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote 'b' to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Future Development Plan:

Anticipated Actions	Anticipated Date
1. 30-day posting	September 2010
2. 30-day pre-ballot period	November 2010
3. Initial ballot	December 2010
4. Recirculation ballot	January 2011
5. Submit to BOT for approval	January 2011
6. File with FERC	February 2011

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-1

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

    4.1. Planning Authority

    4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-1_R1 and TPL-001-1_ R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Compliance Monitor: Regional Reliability Organization.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame
Annually

1.3. Data Retention
None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	 Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c]	 No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	 No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- Demand that is directly served by the elements that are removed from service as a result of the Contingency
- Interruptible Demand or Demand-Side Management
- Demand that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote 'b' to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Future Development Plan:

Anticipated Actions	Anticipated Date
1. 30-day posting	September 2010
2. 30-day pre-ballot period	November 2010
3. Initial ballot	December 2010
4. Recirculation ballot	January 2011
5. Submit to BOT for approval	January 2011
6. File with FERC	February 2011

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-1

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-1_R1 and TPL-001-1_ R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) ~~No interruption of firm Load is allowed except~~An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Future Development Plan:

Anticipated Actions	Anticipated Date
1. 30-day posting	September 2010
2. 30-day pre-ballot period	November 2010
3. Initial ballot	December 2010
4. Recirculation ballot	January 2011
5. Submit to BOT for approval	January 2011
6. File with FERC	February 2011

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-1b

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section - - - - - - - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- Demand that is directly served by the elements that are removed from service as a result of the Contingency
- Interruptible Demand or Demand-Side Management
- Demand that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

Background Information for Interpretation

Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations:

1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)."
2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)."
3. "Include the effects of existing and planned protection systems, including any backup or redundant systems."

Category B of Table 1 (single Contingencies) specifies:

Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:

1. Generator
2. Transmission Circuit
3. Transformer

Loss of an Element without a Fault.

Single Pole Block, Normal Clearing[e]:

4. Single Pole (dc) Line

Note e specifies:

e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."

Conclusion

TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.

This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Future Development Plan:

Anticipated Actions	Anticipated Date
1. 30-day posting	September 2010
2. 30-day pre-ballot period	November 2010
3. Initial ballot	December 2010
4. Recirculation ballot	January 2011
5. Submit to BOT for approval	January 2011
6. File with FERC	February 2011

A. Introduction

1. **Title:** **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. **Number:** TPL-002-1b

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. **Compliance Monitoring Process**

    1.1. **Compliance Monitoring Responsibility**

    Compliance Monitor: Regional Reliability Organizations.
    Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

    1.2. **Compliance Monitoring Period and Reset Timeframe**

    Annually.

    1.3. **Data Retention**

    None specified.

    1.4. **Additional Compliance Information**

    None.

2. **Levels of Non-Compliance**

    2.1. **Level 1:** Not applicable.

    2.2. **Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

    2.3. **Level 3:** Not applicable.

    2.4. **Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating[a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No[b] No[b] No[b] No[b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) ~~No interruption of firm Load is allowed except~~ An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:~~:~~

- ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Future Development Plan:

Anticipated Actions	Anticipated Date
1. 30-day posting	September 2010
2. 30-day pre-ballot period	November 2010
3. Initial ballot	December 2010
4. Recirculation ballot	January 2011
5. Submit to BOT for approval	January 2011
6. File with FERC	February 2011

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-1a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-1_R1 and TPL-003-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
1a	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- Demand that is directly served by the elements that are removed from service as a result of the Contingency
- Interruptible Demand or Demand-Side Management
- Demand that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

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R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.

Proposed Action Plan and Description of Current Draft:

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3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

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- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
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2. **Number:** TPL-003-1a

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4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

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R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-1_R1 and TPL-003-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item "e" on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
1a	TBD	Revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) ~~No interruption of firm Load is allowed except~~An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- ~~(1) Interruption of Load~~ Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- Interruptible Demand or Demand-Side Management
- ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.~~ ~~Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2
Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Future Development Plan:

Anticipated Actions	Anticipated Date
1. 30-day posting	September 2010
2. 30-day pre-ballot period	November 2010
3. Initial ballot	December 2010
4. Recirculation ballot	January 2011
5. Submit to BOT for approval	January 2011
6. File with FERC	February 2011

A. Introduction

1. Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. Number: TPL-004-1

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- Demand that is directly served by the elements that are removed from service as a result of the Contingency, or
- Interruptible Demand or Demand-Side Management
- Demand that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

Future Development Plan:

Anticipated Actions	Anticipated Date
1. 30-day posting	September 2010
2. 30-day pre-ballot period	November 2010
3. Initial ballot	December 2010
4. Recirculation ballot	January 2011
5. Submit to BOT for approval	January 2011
6. File with FERC	February 2011

A. Introduction

1. Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. Number: TPL-004-1

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority’s and Transmission Planner’s assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) ~~No interruption of firm Load is allowed except~~An objective of the planning process is to avoid interruption of Demand. Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to:

- o ~~(1) Interruption of Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency, or
- o Interruptible Demand or Demand-Side Management
- o ~~(2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities.~~ ~~Facilities~~Demand that does not adversely impact overall BES reliability ~~when:~~ where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process.

~~No c~~Curtailment of ~~F~~firm ~~Transmission Service~~transfers is allowed, ~~except~~ when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and ~~those adjustments~~the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Comment Form for SAR and Footnote 'b' in Project 2010-11: TPL Table 1 Order

Please **DO NOT** use this form to submit comments on the 2nd posting for Project 2010-11: TPL Table 1 Order. This comment form must be completed by **October 8, 2010.** This is a 30-day informal comment period. The drafting team will provide a summary response to the one question asked on the comment form, but will not provide an individual response to each comment submitted.

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information
Second Posting for Project 2010-11: TPL Table 1 Order

The 2nd posting is part of the continuing effort to address FERC Orders which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system.

The 2nd posting is the result of the SDT review of the written comments received from industry on the initial ballot and the inputs received from the Technical Conference of August 10, 2010.

While the initial ballot results came close to the required approval percentage, it was clear to the SDT from the cited inputs that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when load could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a

process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential load was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential load was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in the 2nd posting where the SDT has taken the concept of allowing interruption of demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with the ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that likely will be acceptable to all concerned parties.

The 2nd posting provides a revision to TPL Table 1 footnote ‘b’ to provide clarity to industry with regard to the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. The referenced table appears in TPL-001, TPL-002, TPL-003, and TPL-004 so while the FERC Order was for TPL-002, the change is reflected in all 4 standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.

1. The SDT is proposing a revision to footnote ‘b’ in the TPL tables to comply with FERC Orders which required the ERO to clarify TPL-002-0, Table 1 - footnote ‘b’, regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.

   ☐ Yes
   ☐ No
   Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Informal Comment Period Open
September 8 - October 8, 2010

Now available at: http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Project 2010-11 TPL Table 1 Order (Footnote ‘b’)
The TPL Table 1 Order Drafting Team is seeking comments on Table 1 footnote ‘b’ in TPL-001-1 through TPL-004-1 **until 8 p.m. EDT on October 8, 2010**:

FERC Order RM06-16-009 requires the ERO to clarify TPL-002-0, Table 1 - footnote ‘b,’ regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system and originally directed NERC to file the revised standards by June 30, 2010. To meet this directive a proposed revision was posted for “Urgent Action” and balloted from May 17-27, 2010. The proposed revision achieved a quorum (84%) and almost enough affirmative votes (64%) to achieve weighted segment approval; however many balloters provided comments indicating the need for additional modifications. Following the initial ballot, FERC extended the due date to March 31, 2011; thus the project is no longer considered “Urgent Action.”

The drafting team developed a second draft of the proposed revision to TPL Table 1 footnote ‘b’ that reflects consideration of the comments received from industry on the initial ballot and the inputs received from the Technical Conference held on August 10, 2010. The second draft allows interruption of demand without numerical constraints where the application is subject to review and acceptance in an open and transparent stakeholder process.

Because Table 1 appears in TPL-001, TPL-002, TPL-003, and TPL-004, the change is reflected in all four standards:

TPL-001-1 - System Performance Under Normal (No Contingency) Conditions (Category A)

TPL-002-1b - System Performance Following Loss of a Single Bulk Electric System Element (Category B)

TPL-003-1a - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)

TPL-004-1 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

Transition from Reliability Standards Development Procedure Version 7 – to Standard Processes Manual
In accordance with the Standard Processes Manual approved by FERC on September 3, 2010, the drafting team is using an “informal” comment period to solicit stakeholder feedback. The new standard development process allows drafting teams to use informal comment periods. Unlike formal comment periods where a drafting team

provides a response to each comment submitted, with informal comment periods the drafting team provides a summary response to each question asked on its comment form. The summary response will indicate whether stakeholders support the proposal and will identify any additional changes made based on stakeholder comments. With informal comment periods drafting teams are not required to provide an individual response to each comment submitted – this change to the process is intended to give drafting teams more time to deliberate on technical issues, as opposed to deliberating on individual responses to comments. Note that while informal comment periods are allowed in the new standard process for preliminary drafts of proposed standards, formal comment periods are still required for the final draft of each standard.

Instructions

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page:
http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Next Steps

The drafting team will draft and post a summary response to the comments received and, if applicable, a revised 'footnote b.' After reviewing the comments, and determining whether there is a need for additional feedback on the proposed footnote b language, the drafting team will determine its next steps. The next steps may include a 30-day formal comment period or may include a 45-day formal comment period with a ballot pool formed during the first 30 days of that comment period and an initial ballot conducted during the last 10 days of the 45-day comment period.

Project Background

The Assess Transmission Future Needs Standard Drafting Team (Project 2006-02) has developed a clarification to TPL Table 1 — footnote 'b' concerning the loss of load and handling of firm transfers when a single contingency occurs on the transmission system. Since this clarification may present a different interpretation of footnote 'b' than the one presently used by some entities, the SDT is proposing a 60 month implementation plan to allow those entities time to react.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Program Administrator, at monica.benson@nerc.net or at 609.452.8060.

Individual or group. (43 Responses)
Name (32 Responses)
Organization (32 Responses)
Group Name (11 Responses)
Lead Contact (11 Responses)
Question 1 (43 Responses)
Question 1 Comments (43 Responses)

-
Group
Arizona Public Service Company
Jana Van Ness
Yes
Individual
Don Gilbert
JEA
No
The requirement in general is acceptable; however, there needs to be an added "such as" clause to the referenced "...in an open and transparent stakeholder processes." I suggest adding "..."...in an open and transparent stakeholder processes such as the FERC approved regional 890 process that includes the load serving entity affected".
Group
Northeast Power Coordinating Council
Guy Zito
No
1. The introductory paragraph discourages the Interruption of any Demand, implying that no Demand directly connected should be interrupted. However, it is an acceptable practice to allow for some Interruption of Demand that is directly connected to the element that is removed from service. Recommend that the drafting team revise the wording to eliminate this implication, and soften the expectation such that it is recognized that some Interruption of Demand is unavoidable by system configuration, but that each entity should establish a reasonable limit on how much demand can be interrupted due to the loss of an element. 2. The Statement that “However, Demand may need to be interrupted in limited circumstances to address BES performance requirements” in the introductory paragraph contradicts bullet 3 “Demand that does not adversely affect BES …” 3. The third Bullet is confusing. Suggest revising the wording to clarify the adverse impact to the BES system, documentation expectations, and to answer fundamental questions such as who has the authority to decide the use if the stakeholder process is “accepting”, and the necessity of having a stakeholder process. It is unlikely that the interruption of Demand will adversely impact the BES system. This constraint is too broad. The language in this bullet also allows that non-consequential Demand interruption could be used to mitigate reliability violations arising from the NERC Category B contingency events (i.e., single element contingencies). 4. In the second paragraph, the conditions when interruption of Firm Transfers may be used are not specified. 5. In the last sentence of the second paragraph, “would” should be replaced by “must”. Alternatively, possible rewording of footnote “b” to be considered: b) An objective of the planning process should be to minimize the likelihood of interrupting Demand and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements or other local reasons which have no adverse impact on overall BES reliability or the interconnected BES. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Demand that does not adversely impact overall reliability of the BES or the interconnected BES and where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of available resources, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected. The Drafting Team should reconsider the use of “Load” as opposed to “Demand”. By definition (NERC Glossary dated April 20, 2010) Demand is: “1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.” Load is defined as: “An end-use device or customer that receives power from the electric system.” This terminology is more appropriate to the application used in the Table.
Group

SERC Planning Standards Subcommittee
Philip R. Kleckley
No
The revised text relating to the planning process exceeds what is appropriate for a reliability standard. Existing open and transparent stakeholder processes focus on larger system issues and not on local load serving. We suggest the following: Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Interruptible Demand or Demand-Side Management o Demand that does not adversely impact overall BES reliability and is made temporarily radial as a result of the Contingency, where that Demand must be interrupted to meet performance requirements. Curtailment of firm transfers is allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected. “The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.”
Individual
RoLynda Shumpert
South Carolina Electric and Gas
No
SCE&G believes the first sentence "An object of the planning process is to avoid interruption of Demand." goes beyond what is appropriate for a reliability standard and therefore should be deleted. Also, the part of the sentence that states "and where the application is subject to review and acceptance in an open and transparent stakeholder process" goes beyond what is appropriate for a reliability standard and should be deleted.
Individual
Laura Zotter
ERCOT ISO
Yes
Group
PacifiCorp
Sandra Shaffer
No
PacifiCorp believes that the current version of footnote “b” is an improvement over the language that currently exists in the standard, except for one component of the revised footnote. The third bullet in the draft standard currently limits the interruption of Demand if it does not adversely impact overall BES reliability, where the circumstances describing the use of the interruption are documented (including alternatives evaluated) and the application is subject to review and acceptance in “an open and transparent stakeholder process.” PacifiCorp believes that the language requiring review and acceptance of an application of demand interruption through any sort of stakeholder process should be removed. It is not practical or effective to prescribe that either this standard or any other standard requires stakeholder approval in order to maintain compliance. As presently drafted, this requirement for stakeholder review and acceptance appears to be inconclusive and indeterminate as to what is required for registered entities to comply. Instead, this third bullet should require the documentation, by the Planning Authority and Transmission Planner, of the circumstances describing the use of Demand interruption – including methodologies used, assumptions relied upon, and alternatives evaluated – as part of the Planning Authorities’ and/or Transmission Planners’ documentation of results in their annual Reliability Assessments. These annual assessments are already submitted to the appropriate Regional Reliability Organization pursuant to TPL-002-1b Requirement R3. This annual assessment can be provided by the ERO to other appropriate third parties upon their request.
Individual
Greg Rowland
Duke Energy
Yes
Duke Energy strongly supports this revised footnote ‘b’. We believe that it provides for appropriate consideration of stakeholder input in decision-making for local reliability issues, while maintaining the reliability of the Bulk Electric System.
Individual
Steve Stafford
Georgia Transmission Corporation
Yes

Group
PPL Corp
John Cummings
Yes
PPL believes that Footnote b as described in TPL-002-1b, Draft 2, August 30, 2010 is fine provided an accompanying Requirement (with appropriate VRF and VSL) and Measure is added to the TPL standard(s) to require and document notification of the affected Demand parties and the involvement of the affected Demand parties in an open process as described by Footnote b, third bullet.
Individual
John Canavan
NorthWestern Energy
No
In addition to the three bullet items, add a fourth bullet item to the list of limitations under the body of footnote b: “In no case will a total loss of load that is less than 50 MW be considered a violation of this standard.”
Individual
Tim Ponseti
TVA Transmission Planning & Compliance
No
TVA supports FERC's actions on improving reliability of the BES; however, TVA believes that the new proposal is focusing more on reliability of local loads than on the overall reliability of the BES. Footnote b should focus only on the overall reliability of the BES. Reliability of local loads should be addressed outside the TPL standards and therefore should not be used/referenced in footnote b. Also existing stakeholder processes (referred to in the SDT proposal) typically focus on larger system issues and not on local load serving. Thus TVA believes that some local load should be allowed to be dropped in order to maintain BES reliability. However TVA does believe that there should be a limit of how much load can be dropped in order to maintain BES reliability. TVA believes that 50 MW is a reasonable number for this limit. Based on the above, TVA proposes substituting the following for the revised footnote b: Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: Demand that is directly served by the elements that are removed from service as a result of the Contingency Interruptible Demand or Demand-Side Management Demand that does not adversely impact overall BES reliability, where that Demand (not to exceed 50 MW) must be interrupted to meet performance requirements. Curtailment of firm transfers is allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected.
Individual
Gordon Rawlings
BC Hydro
No
The SDT is to be commended for their efforts to develop clear, unambiguous language for Footnote “b”. From the discussions that have taken place it seems that there are many different perspectives and to get agreement on specific language will be very difficult. We believe that it would be useful to identify the main issues that Footnote “b” needs to address and we consider those main issues to be: • Definitions of (a) Consequential Load Loss, (b) Firm Demand, (c) Firm Transmission Capability (as distinct from the OATT term, “Firm Transmission Service”), (d) Firm Transfer (this could be defined as transfers using the OATT’s Firm Transmission Service, (e) Manual System Adjustments (capitalized in the Category C section of TPL-001, but not defined in the NERC Glossary) and (f) the Bulk Electric System (BES). • Identifying permissible Demand/Transfer curtailment actions for (a) the planning studies simulating the Category B event itself and (b) the planning studies associated with determining acceptable actions for preparing for the next set of contingencies should the initial single contingency be prolonged (ie, last several weeks). This would define the acceptable (pre-emptive) “Manual System Adjustments” of Category C events. • Define separate acceptable curtailment actions for (a) curtailment of Demand (ie, end-user load) and (b) curtailment of market to market transfers, that very rarely, if ever, result in the loss of any end-user load. • Define the planning studies required to determine the acceptability of the impacts on the BES resulting from curtailments in a “remote” part of the system that have been accepted by those directly affected by those curtailments. At this point we don’t have specific language to suggest, but we do have the following comments that we hope will help: A. Interruption of Demand: A.1. Consider improving the definition of “Firm Demand” in the NERC Glossary that now reads, “That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions”. Perhaps it could be changed to something like, “That portion of the Demand that the planned transmission system must be able to supply without interruption for Category B events. A.2. Consider stating in Footnote “b” that curtailment of Firm Demand is (a)

not permitted in the simulation of the N-1 event itself and (b) it is not permitted as part of the (pre-emptive) “Manual System Adjustments” needed to prepare for the next set of contingencies should the initial single contingency be prolonged (ie, last several weeks). B. Interruption of Firm Transfers: B.1. “Firm Transfers” could be defined as transfers using the OATT’s Firm Transmission Service, but consider developing a system reliability-based term for “Firm Transmission Capability” instead of referring to the tariff-based NERC definition of “Firm Transmission Service”. This would recognize the difference between planning standards and commercial/tariff rules. The NERC definition of “Firm Transmission Service” is now, “The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption”. Transmission tariffs address the priority of curtailments when the loading on a transmission path needs to be reduced for whatever reason (single- or multiple-contingencies). The NERC transmission planning standards need a system reliability definition like, “Firm Transmission Capability” is the transmission capability across a cut-plane, on a defined transmission path or across a defined flowgate that is available, before any manual corrective actions are taken, following the worst Category B event under the most onerous normal system conditions considering all plausible generation dispatch patterns and the full range of expected load levels.” B.2. Consider stating in Footnote “b” that curtailment of Firm Transfers is only permitted to the extent that redispatch of generation can be implemented so that delivery to the Firm Transfer recipient is not interrupted (a) in the planning studies of the Category B event itself and (b) as part of the (pre-emptive) “Manual System Adjustments” needed to prepare for the next set of contingencies should the initial single contingency be prolonged (ie, last several weeks). C. General Comments: C.1. Consider replacing the first bullet of the proposed Footnote “b” with simply “Consequential Load Loss” since the NERC Project 2006 02 (TPL 001) Standard Drafting Team is introducing the following definition: Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault C.2. Consider removing “Demand-Side Management” (DSM) from the second bullet because that term is too general. The present definition of DSM in the NERC Glossary is: “The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use”. C.3. Consider being more specific on what constitutes acceptable “Interruptible Demand”, like: “Interruptible Demand that is part of an automatic real-time Direct Control Load Management (DCLM) system that is activated by the contingencies that require it and that is a completely “dual-redundant” scheme including all communications equipment. The DCLM system must result in automatic curtailment of Demand that is fast enough to maintain all BES system performance standards (eg, voltage stability, voltage dip, etc)”. C.4. Consider eliminating the description of how interrupting Demand that does not adversely impact overall BES reliability was accepted (ie, the stakeholder process, etc). If such a process were undertaken and it resulted in acceptance that the Demand could be curtailed for Category B events, wouldn’t that simply mean that the Demand was “Interruptible Demand”. It really doesn’t matter what process resulted in it being accepted. The key considerations are that (a) if the interruption of that Demand is necessary to maintain BES reliability, then it must be interrupted in a very reliable manner (ie, dual redundant scheme, etc) and (b) if the interruption of that Demand is not necessary to maintain the reliable performance of the BES, then that should be confirmed by the planning studies (ie, it doesn’t need to have an expensive, sophisticated, dual-redundant DCLM scheme since the impact on the BES is acceptable even if the scheme doesn’t work). D. Additional Questions related to Curtailment of Firm Transfers: In the past, the latter part of Footnote B read: “To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.” The last part of the proposed Footnote B now reads: “Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected.” We would like to understand the implications of the proposed Footnote B as it relates to curtailment of Firm Transfers (as per definition proposed earlier) for the following questions: 1) In the most recent draft of Footnote B, why was the NERC defined term ‘Firm Transmission Service’ replaced with the non-defined term ‘firm transfers’? 2) In the most recent draft of Footnote B, why was the tone softened from “No curtailment of Firm Transmission Service is allowed, except…” to “Curtailment of firm transfers is allowed when…”? 3) Assuming an outage of a single transmission line (N-1 Category B event) has occurred and assuming that no “resources [are] obligated to redispatch” for this outage, would a transmission provider be allowed to curtail Firm Transmission Service (NERC defined term) that it has sold in order to prepare to withstand the next worst credible contingency? 4) Would transmission providers be allowed to sell Firm Transmission Service on a path above what could be delivered with any one element of that path out of service and a range of operating conditions? 5) If the proposed Footnote B is approved, would utilities have to reinforce their system (within 60 months) to ensure that Firm Transmission Service for particular paths would not be curtailed can be delivered when any one element of that path is out of service? 6) If a transmission provider employs Generation Dropping for single contingencies in order to support Firm Transmission Service between regions, and assuming there are no provisions for obligated re-dispatch, would the proposed Footnote B force a recalculation of firm vs non-firm transfer capability? 7) Path 66 (PACI) and Path 65 (PDCI) can both see significant derates in their firm transfer capability for single contingencies. How would the proposed Footnote B impact Firm Transmission on these paths?
Group
MRO's NERC Standards Review Subcommittee
Carol Gerou
No

The revised draft is a significant improvement over the first draft. However, we suggest the following minor changes: 1. The criterion of “adversely affect overall BES reliability” is undefined and maybe subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest adding the words “as defined by each Transmission Planner or Planning Authority”. 2. The term of “firm transfers” is undefined and maybe subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest establishing a definition for the term, reverting to the “Firm Transmission Service” term, or using another appropriate defined term.
Individual
Jon Kapitz
Xcel Energy
Yes
Xcel Energy supports the new interpretation that would allow curtailment of firm transfers or demand for limited conditions where the integrity of bulk electric system is not compromised. However Xcel Energy seeks some clarification regarding the following: The 3rd bullet point in footnote b will need to clarify whether the demand interruption can be done after the contingency, or before the contingency. If it is allowed after the contingency, then the standard would allow violation of voltage or thermal loading criteria for a brief period, after contingency and, before demand curtailment happens. Is this acceptable based on the new interpretation? Since TPL-002 standard deals with NERC Category B contingencies, and footnote b states that curtailment of firm transfers is allowed, it should be clarified if this curtailment is allowed before or after the contingency. If the curtailment is allowed only after the contingency, then the system would be in violation of the thermal or voltage criteria for a brief period till the generation is re-dispatched. Is this allowed by the new interpretation? If curtailment is only allowed in preparation of the contingency, then the firm transfers would be curtailed during system intact conditions, in preparation for the first contingency, resulting in violation of TPL-001 standard. Is this allowed by the new interpretation?
Individual
John Sullivan
Ameren
No
The revised text to footnote b relating to the planning process exceeds what is appropriate for a reliability standard. Existing open and transparent stakeholder processes focus on larger system issues rather than on local load serving issues. We suggest the following text for footnote b: Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Interruptible Demand or Demand-Side Management o Demand that does not adversely impact overall BES reliability and is made temporarily radial as a result of the Contingency, where that Demand must be interrupted to meet performance requirements. Curtailment of firm transfers is allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected.
Individual
Darcy O'Connell
California ISO
Yes
1) Regarding the 2nd bullet provision, we suggest: Interruptible Demand or Demand-Side Management that has been reviewed and approved by the Planning Authority. 2) Regarding the 3rd bullet provision, we suggest: Demand interruption that does not adversely impact overall BES reliability…. 3) Also regarding the 3rd bullet provision, we suggest replacing acceptance with clarification to read “where the application is subject to review and clarification in an open and transparent stakeholder process."
Individual
Doug Hohlbaugh
FirstEnergy
No
FirstEnergy appreciates the efforts of the Assess Transmission Future Needs SDT in reaching a reasonable proposal for clarifying Table 1 footnote B presented in the TPL-001 through TPL-004 standards. We also commend NERC staff for convening an industry technical conference to discuss the topic and FERC staff for their participation in the technical conference as the industry carefully considered various perspectives. The proposed footnote B is much improved from the prior draft proposals. One change that FirstEnergy proposes is to strike the text following the semicolon in the third bullet item which states “and where the application is subject to review and acceptance in an open and transparent stakeholder process.” This text may be intended as explanatory but has the appearance of mandating an approval process that will be auditable through the TPL reliability standards. The statement is not

needed within the framework of mandatory reliability requirements as FERC Order 890 already mandates an open and transparent process related to the planning of the bulk electric system. FERC via the 890 Final Rule modified the pro forma Open-Access Transmission Tariff to require open and transparent stakeholder process to better ensure no undue discrimination and access to the transmission system. The Final Rule beginning at paragraph 418 discusses reform to the Coordinated, Open and Transparent Planning of the transmission system. The Commission direction included eight planning principles required to be within the open process – one of which is dispute resolution. It should be well understood that the transmission planner and planning coordinator share and disseminate all of their planning study results and proposed corrective actions – including the proposed use of Demand interruption – as part of their adherence to Order 890. We appreciate the SDT's careful consideration of our comments.
Individual
Orlando A Ciniglio
Idaho Power
Yes
footnote 'b' is silent with respect to planned removal from service of certain generators. I believe there are many conditions out there where a single contingency can initiate a planned (RAS-initiated) removal of generation. The fact that this is mentioned in footnote 'c', under multiple contingencies, begs the need for futher elaboration/discussion of this option under single contingencies in footnote 'b'.
Individual
Michael Lombardi
Northeast Utilities
No
NU agrees with the language of the proposed revision to Footnote b EXCEPT FOR bullet #3 which suggests that non-consequential demand interruption could be used to mitigate reliability violations arising from the NERC Category B contingency events (i.e., single element contingencies).
Individual
Thad Ness
American Electric Power
Yes
Individual
JC Culberson
ERCOT
No
The introductory paragraph of footnote b includes policy language. Since this is a reliability standard—and not a policy directive—the general narrative setting forth the desired policy goal of minimizing load-shedding is misplaced. Including policy language can cloud the specific issues the standard attempts to address, and ERCOT recommends deleting the first two sentences in the introductory paragraph. The next sentence in the introductory paragraph goes on to state, generally, that demand may be interrupted to "address BES performance requirements." This phrase is vague. To which performance requirements does this refer? The intent is not clear. If the intent is to generally recognize the need to shed load to respect NERC standards and to allow flexibility for an entity to exercise discretion relative to meeting BES performance requirements, then that intent should be clearly reflected in the language. Furthermore, the last sentence of the introductory paragraph and the subsequent bullet points are arguably inconsistent with this approach, because they could be viewed as removing an entity's flexibility/discretion by limiting the circumstances when load can be shed. The second bullet point is unnecessary, because it is already apparent that interruptible demand/demand side management programs can be used according to their terms. This could create confusion in that it could be implied that, absent the need to use these to meet BES performance requirements, using them otherwise is inconsistent with/not allowed under footnote b. Simply put, those products are not load shedding as contemplated by this footnote. Therefore they should not be listed here. With respect to the third bullet point, the phrase "demand that does not adversely impact overall BES reliability" is not adequately defined, and provides opportunity for confusion. This is an ambiguous phrase and can't be linked back to objective NERC standards/requirements. The bullet points should avoid ambiguity to mitigate ambiguity risk in audits. In addition, the last part of the language in this bullet imposing an open and transparent stakeholder process is unclear. What is the intent behind requiring review in a stakeholder process? If it is to establish the ability of the entity to develop load shedding procedures beyond those explicitly contemplated in footnote b, ERCOT questions if it is reasonable for the responsible entity to be required to get "permission" from stakeholders to implement reliability measures related to its obligation as the functional entity. Again, the language simply is not clear. Accordingly, ERCOT recommends this bullet point be removed. If it is retained, it should be revised consistent with these comments to remove ambiguous language to mitigate potential confusion around the meaning/scope of the footnote in the administration of the CMEP. In addition, ERCOT recommends revising the draft footnote b to allow for planned Demand interruption as a means of mitigation during interim periods when a unanticipated (such as unexpected demand growth or unit retirements) or temporary change on the system occurs in a

timeframe that is shorter than the time necessary to plan and implement the system upgrades necessary to avoid the Demand interruption. Finally, in the last paragraph of footnote b, it isn't clear why "Transmission Service" was changed to "transfers." Firm transmission service is a service provided in some regions, and it provides relative value to other types of services—e.g., non-firm and network. The mention of transmission service may also be irrelevant in this footnote, since the allowance of its interruption doesn't also allow for load shedding. Therefore, ERCOT recommends eliminating the last paragraph of footnote b.
Group
Bonneville Power Administration
Denise Koehn
Yes
Individual
Kasia Mihalchuk
Manitoba Hydro
Yes
The changes to Table 1 Note b proposed by the SDT for this second posting are a reasonable approach to the issue of interrupting of "Firm Demand". The requirement to evaluate alternatives to dropping of Firm Demand in a transparent stakeholder process should provide the verification of cost over benefit on a case by case basis. I propose the following editorial changes: 1. The change of "Firm Transmission Services" made in Table 1 should be also be made in each TPL standard as R1 refers to "projected Firm (non-recallable reserved) Transmission Services. 2. Since "Firm Demand" is a defined term, ensure it is capitalized throughout the standard. There is one instance where it is not.
Individual
Charles Lawrence
American Transmission Company
No
The revised draft is a significant improvement over the first draft. However, we suggest the following minor changes: 1. The criterion of "adversely affect overall BES reliability" is undefined and may subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest adding the words "as defined by each Transmission Planner or Planning Authority". 2. The term of "firm transfers" is undefined and may subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest establishing a definition for the term of "firm transfers", reverting to the "Firm Transmission Service" term, or using another appropriate NERC defined term.
Individual
Kathleen Goodman
ISO New England Inc.
No
ISO New England does not allow non-consequential load loss for first contingencies in Planning Analysis, and as an overall matter, ISO-NE believes that the appropriate step is for NERC to modify the footnote in line with the original FERC Order. However, ISO-NE offers the following recommendation to improve the proposed language for footnote b if it is to be retained similar to what has been proposed. In short, ISO-NE proposes changing the third sub-bullet, because the provision is both unnecessary and inappropriate for a NERC Standard. First, the sub-bullet is redundant, because the Commission has ordered that companies add to their Open Access Transmission Tariffs an open and transparent planning process. If Transmission Planners establish their system planning assessments through those processes, then there should be no question that the Planner's assessments have been effectively communicated to the region. Second, the passive nature of the language (i.e., "where the application is subject to review and acceptance…") is unclear as it suggests that someone other than the Planning Coordinator/Transmission Planner is responsible for determining what belongs in a long-term system assessment. Including Demand-Side Management in the standard also appears redundant as Demand Response is used as an asset in the same manner as generation resources. b) When interruption of Demand is utilized within the planning process, such interruption is limited to: 1) Demand that is directly served by the elements that are removed from service as a result of the Contingency. 2) Interruptible Demand or Demand-Side Management 3) Instances where the planned or controlled interruption of Demand results in System performance which meets the requirements of Table 1 for Category B contingencies. When such Demand interruption is utilized in an assessment, the use of such actions must be limited to small portions of the system, be operationally achievable, be of limited duration, and be documented therein.
Individual
Dan Rochester
Independent Electricity System Operator
Yes

Individual
Ed Davis
Entergy Services
No
Entergy disagrees with the proposed language in the third bullet for two reasons. 1. While Entergy supports the idea of “an open and transparent stakeholder process” regarding the use of non-consequential load loss. It is unclear how such a process could be fairly implemented as competing stakeholder interests could prevent resolution. Stakeholders should be defined as those stakeholders whose load could be shed per footnote b, not any and all stakeholders. 2. The “is subject to review and acceptance” implies that some formal voting process would be required by stakeholders. Is this the SDT’s intent? If so would such a process be developed as part of the standard or would it be left up to TO’s? If non-consequential load loss was deemed an acceptable solution across a SEAM, would the TO’s jointly serving the load need to agree?
Group
Dominion
Louis Slade, Jr.
Yes
Individual
Terry Harbour
MidAmerican Energy
No
While the TPL note “b” approach has improved, MidAmerican has concerns that including the wording “review and acceptance” goes beyond the FERC Order 890 order, process, and intent of including the open review process. Therefore, to align with FERC Order 890, the “review and acceptance” should be replaced with “subject to comment”. Anything more exceeds FERC Order 890 and the reason why the review process was included. In the end, Transmission Owning and Operating entities must have final say in the operation of the grid. Entities can comment, but cannot obstruct Transmission Owning and Operating entities from properly operating the grid or reliability could be reduced.
Group
Southern Company
Andy Tillery
No
The revised text relating to the planning process exceeds what is appropriate for a reliability standard. Existing open and transparent stakeholder processes focus on larger system issues and not on local load serving. We suggest that the drafting team go back to the concept of local load being the load that is made temporarily radial by the contingency. That was a much better approach.
Individual
Patrick Farrell
Southern California Edison Company
Yes
SCE appreciates the efforts of the NERC Standards Drafting Team and believes that the team has admirably worked to meet FERC's expectations. SCE would suggest that Footnote "b" be revised to include a semi-colon(;) after the first sub-paragraph and a semi-colon(;) followed by an "and" after the second sub-paragraph, to convey that the three sub-paragraphs are alternative, rather than additive methods for satisfying the requirements for "interruptions."
Individual
Jonathan Appelbaum
United Illuminating Co
No
United Illuminating believes that for TPL Category B contingencies no planned or controlled (non-consequential) interruption of firm demand should occur as a general philosophy for planning the Bulk Electric System (BES). Recognizing there are certain areas of the BES that have unique circumstances that may warrant an exception to this, UI suggests the addition of language that recognizes the limited application of non-consequential load interruption with a process that requires a case-by-case acceptance of such application by the Regional Entity or NERC.
Individual
Michael Moltane
ITC
Yes

The proposed language for the new TPL-001-1 Table 1 footnote b is acceptable to ITC.
Individual
Gregory Campoli
New York Independent System Operator
Yes
The NYISO agrees in principle with the proposed changes, but recommends the following modifications: 1. The introductory paragraph discourages the Interruption of any Demand, implying that no Demand directly connected should be interrupted. However, it is an acceptable practice to allow for some Interruption of Demand that is directly connected to the element that is removed from service. The introductory paragraph is immaterial to the requirement, and therefore unnecessary with the exception of the last sentence which starts the bulleted list. 2. Interruptible demand is an operation tool and not a transmission planning tool, while Demand-Side Management is typically embedded in the load forecast used in the planning process. The second bullet therefore may not be necessary or applicable here, though it is helpful in making clear those are acceptable forms of interruption. 3. The third bullet is confusing. Suggest revising the wording to clarify the adverse impact to the BES system and documentation expectations. Recommend removing reference to the application being subject to review and acceptance in an open and transparent stakeholder process; this is inherent to all documentation and does not need to be emphasized in a footnote. 4. In the last sentence of the last paragraph, “would” should be replaced by “must”. 5. The Drafting Team should reconsider the use of “Load” as opposed to “Demand”. By definition (NERC Glossary dated April 20, 2010) Demand is: 1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.” Load is defined as: “An end-use device or customer that receives power from the electric system.” This terminology is more appropriate to the application used in the Table. Possible rewording of footnote “b” to be considered: b) Under the limited circumstances when interruption of Load is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Load that is directly served by the elements that are removed from service as a result of the Contingency o Interruptible Load or Demand-Side Management o Demand that does not adversely impact overall BES reliability where the circumstances for the use of such Load interruption and alternatives evaluated are documented. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of available resources, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions must also be respected.
Individual
David Kiguel
Hydro One Networks Inc.
No
1. The introductory paragraph discourages the Interruption of any Demand, implying that no Demand directly connected should be interrupted. However, it is an acceptable practice to allow for some Interruption of Demand that is directly connected to the element that is removed from service. Recommend that the drafting team revise the wording to eliminate this implication, and soften the expectation such that it is recognized that some Interruption of Demand is unavoidable by system configuration, but that each entity should establish a reasonable limit on how much demand can be interrupted due to the loss of an element. 2. The Statement that “However, Demand may need to be interrupted in limited circumstances to address BES performance requirements” in the introductory paragraph contradicts bullet 3 “Demand that does not adversely affect BES …” 3. The third Bullet is confusing. Suggest revising the wording to clarify the adverse impact to the BES system, documentation expectations, and to answer fundamental questions such as who has the authority to decide the use if the stakeholder process is “accepting”, and the necessity of having a stakeholder process. It is unlikely that the interruption of Demand will adversely impact the BES system. This constraint is too broad. The language in this bullet also allows that non-consequential Demand interruption could be used to mitigate reliability violations arising from the NERC Category B contingency events (i.e., single element contingencies). 4. In the second paragraph, the conditions when interruption of Firm Transfers may be used are not specified. 5. In the last sentence of the second paragraph, “would” should be replaced by “must”. Alternatively, possible rewording of footnote “b” to be considered: b) An objective of the planning process should be to minimize the likelihood of interrupting Demand and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements or other local reasons which have no adverse impact on overall BES reliability or the interconnected BES. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Demand that does not adversely impact overall reliability of the BES or the interconnected BES and where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of available resources, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected. The Drafting Team should reconsider the use of “Load” as opposed to “Demand”. By definition (NERC Glossary dated April 20, 2010) Demand is: “1. The rate at which electric energy is

delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer." Load is defined as: "An end-use device or customer that receives power from the electric system." This terminology is more appropriate to the application used in the Table.
Individual
Jason Marshall
Midwest ISO
No
Overall, we believe the changes are reasonable. However, we propose to strike "and where the application is subject to review and acceptance in an open and transparent stakeholder process." Stakeholder review processes should not be mandated through enforceable standards as they do not provide a clear benefit to reliability. Further, FERC Order 890 already mandates an open and transparent process related to the planning of the bulk electric system.
Individual
Claudiu Cadar
GDS Associates Inc.
No
We appreciate all the work conducted by SDT to adjust current footnote "b" however, we disagree with the current approach as follows below: - The definition does not go far enough with recognition that interruption of Demand should be mitigated if at all possible. The previous language may have been inadequate, but the current language does not encourage the TP to develop mitigation plans that could be implemented as an alternative to Demand interruption. - Use of Interruptible Demand should only be implemented if the Transmission Planner can point to a contract between the Transmission Provider and Transmission Customer that permits load curtailment. - Under FERC Order 890, Conditional Firm transmission service can be granted for entities who voluntarily acknowledge the right of the Transmission Provider to curtail their transaction or provide re-dispatch. This should be the only transfer which can be utilized in the Planning Horizon for interruption of Demand for Note b. Suggested language to find the balance point in the tone of this note is below: "An objective of the planning process is to develop mitigation plans that do not call for the curtailment of Demand, as interruption of Demand places specific customer groups at a reliability risk that varies from their counterparts in other areas of the BES. There may be rare instances, however, where interruption of Demand can be considered a short-term bridge to a mitigation plan which does not rely on negatively impacting certain customer segments. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency, o Interruptible Demand or Demand-Side Management, where the Customer has given explicit rights to the Transmission Provider for curtailment of their Demand, o Demand, other than Interruptible Demand or Demand-Side Management, that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand are documented, including alternatives evaluated; where the Load-Serving Entity who has responsibility for serving such Demand has agreed to the curtailment, and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of Firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch per the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of and firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected. In addition, any Conditional Firm transfers may be curtailed, in accordance with the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider."
Individual
Chifong Thomas
Pacific Gas and Electric Co.
Yes
Group
IRS Standards Review Committee
Ben Li
Yes
Individual
Catherine Koch
Puget Sound Energy
Yes
PSE agrees with the foot note b as stated. As it states for any category B outage there wouldn't be any non-

consequential load loss allowed unless a full study is performed with evaluation of alternatives and is approved by stakeholders. Also, one could curtail firm transfers if re-dispatch of resource is possible. However, there is still some ambiguity in when approval from stakeholders (time-line)should be sought and who the stakeholders could be (customers, effected utilities etc.). Hence, PSE would like to revise the footnote by adding the following to the end of the footnote, ".... at least 2 years prior to the implementation. All the affected parties must review and agree upon the loss of demand proposal."
Group
IRC Standards Review Committee
Ben Li
Yes
Individual
Harold Wyble
Kansas City Power & Light
No
KCPL appreciates the efforts of the Assess Transmission Future Needs SDT in reaching a reasonable proposal for clarifying Table 1 footnote B presented in the TPL-001 through TPL-004 standards. We also commend NERC staff for convening an industry technical conference to discuss the topic and FERC staff for their participation in the technical conference as the industry carefully considered various perspectives. Although the proposed footnote B is much improved from the prior draft proposals, KCPL proposes is to strike the text following the semicolon in the third bullet item which states “and where the application is subject to review and acceptance in an open and transparent stakeholder process.” This text may be intended as explanatory but has the appearance of mandating an approval process that will be auditable through the TPL reliability standards. The statement is not needed within the framework of mandatory reliability requirements as FERC Order 890 already mandates an open and transparent process related to the planning of the bulk electric system. FERC via the 890 Final Rule modified the pro forma Open-Access Transmission Tariff to require open and transparent stakeholder process to better ensure no undue discrimination and access to the transmission system. The Final Rule beginning at paragraph 418 discusses reform to the Coordinated, Open and Transparent Planning of the transmission system. The Commission direction included eight planning principles required to be within the open process – one of which is dispute resolution. It should be well understood that the transmission planner and planning coordinator share and disseminate all of their planning study results and proposed corrective actions – including the proposed use of Demand interruption – as part of their adherence to Order 890.

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on TPL Table 1 Order (footnote 'b') — Project 20010-11

The TPL Table 1 Order Drafting Team thanks all commenters who submitted comments on the revised footnote. These standards were posted for a 30-day informal public comment period from September 8, 2010 through October 8, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 42 sets of comments, including comments from more than 96 different people from approximately 75 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

Comments can be reviewed in their original format on the following project page:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Industry response was divided in relation to support for the proposed footnote 'b' which was posted for an informal comment period through October 8, 2010. Although there were a number of supporters for the proposed footnote they were outnumbered by the commenters who did not support the footnote text for various reasons and offered their views and concerns.

The Standard Drafting Team (SDT) carefully considered the feedback provided including minority opinions such as not allowing Demand interruption at all and has made clarifying revisions to the footnote 'b' text.

The revised footnote 'b' is:

b) An objective of the planning process ~~is to avoid~~ should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. ~~Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process~~. However, it is recognized that Demand ~~may need to~~ will be interrupted if it is directly served by the elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- ~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~
- Interruptible Demand or Demand-Side Management
- ~~Demand that does not adversely impact overall BES reliability where the c~~Circumstances ~~describing~~ where the use of ~~such~~ Demand interruption are documented, including alternatives evaluated; and where the ~~application~~ Demand interruption is subject to review ~~and acceptance~~ in an open and transparent stakeholder process that includes addressing stakeholder comments.

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Based on the review of comments received and the fact that only clarifying changes were made due to those comments, the SDT is recommending that this project be moved forward to balloting.

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

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

Index to Questions, Comments, and Responses

The Industry Segments are:

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council	10									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Micahel Schiavone	National Grid	NPCC	1
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Dean Ellis	Dynegy Generation	NPCC	5
8.	Brian Evans-Mongeon	Utility Services	NPCC	8
9.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	Chantel Haswell	FPL Group, Inc.	NPCC	5
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Michael R. Lombardi	Northeast Utilities	NPCC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	Saurabh Saksena	National Grid	NPCC	1

2.	Group	Philip R. Kleckley	SERC Planning Standards Subcommittee	1, 3, 5

Additional Member	Additional Organization	Region	Segment Selection	
1.	Bob Jones	Southern Company Services - Trans	SERC	1
2.	John Sullivan	Ameren	SERC	1
3.	Charles Long	Entergy	SERC	1
4.	Jim Kelley	PowerSouth Energy Cooperative	SERC	1
5.	Pat Huntley	SERC Reliability Corporation		10

3.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	WPS Corporation	MRO	3, 4, 5, 6
4.	Jason Marshall	Midwest ISO Inc.	MRO	2
5.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
6.	Ken Goldsmith	Alliant Energy	MRO	4
7.	Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6
8.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
9.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
10.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

11.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
12.	Scott Nickels	Rochester Public Utilties	MRO	4
13.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6

4.	Group	Denise Koehn	Bonneville Power Administration	1, 3, 5, 6

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chuck Matthews	BPA, Transmission Planning	WECC	1
2.	Berhanu Tesema	BPA, Transmission Planning	WECC	1
3.	Kyle Kohne	BPA, Transmission Planning	WECC	1
4.	Kendall Rydell	BPA, Transmission Planning	WECC	1
5.	Rebecca Berdahl	BPA, Long Term Sales and Purchases	WECC	3

5.	Group	Louis Slade, Jr.	Dominion	1, 3, 5, 6

	Additional Member	Additional Organization	Region	Segment Selection
1.	Angela Park	Electric Transmission	SERC	1, 3
2.	John Loftis	Electric Transmission	SERC	1, 3
3.	Mike Garton	Electric Market Policy	NPCC	5, 6
4.	Michael Gildea	Electric Market Policy	RFC	5, 6

6.	Group	Ben Li	IRC Standards Review Committee	2

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Phillips	MISO	MRO	2
2.	Partick Brown	PJM	RFC	2
3.	James Castle	NYISO	NPCC	2
4.	Mark Thompson	AESO	WECC	2
5.	Charles Yeung	SPP	SPP	2
6.	Greg Van Pelt	CAISO	WECC	2
7.	Matt Goldberg	ISO-NE	NPCC	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Individual	Jana Van Ness	Arizona Public Service Company	X		X		X					
8.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
9.	Individual	John Cummings	PPL Corp	X		X		X					
10.	Individual	Andy Tillery	Southern Company	X		X							
11.	Individual	Don Gilbert	JEA	X		X		X					
12.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
13.	Individual	Laura Zotter	ERCOT ISO		X								
14.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
15.	Individual	Steve Stafford	Georgia Transmission Corporation	X									
16.	Individual	John Canavan	NorthWestern Energy	X									
17.	Individual	Tim Ponseti	TVA Transmission Planning & Compliance	X		X		X				X	
18.	Individual	Gordon Rawlings	BC Hydro	X	X	X		X					
19.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
20.	Individual	John Sullivan	Ameren	X		X		X	X				
21.	Individual	Darcy O'Connell	California ISO		X								
22.	Individual	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
23.	Individual	Orlando A Ciniglio	Idaho Power	X		X		X					
24.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
25.	Individual	Thad Ness	American Electric Power	X		X		X	X				
26.	Individual	JC Culberson	ERCOT		X								
27.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
28.	Individual	Charles Lawrence	American Transmission Company	X									
29.	Individual	Kathleen Goodman	ISO New England Inc.		X								
30.	Individual	Dan Rochester	Independent Electricity System Operator		X								
31.	Individual	Ed Davis	Entergy Services	X		X		X	X				
32.	Individual	Terry Harbour	MidAmerican Energy	X		X		X	X				
33.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				
34.	Individual	Jonathan Appelbaum	United Illuminating Co	X									
35.	Individual	Michael Moltane	ITC	X									
36.	Individual	Gregory Campoli	New York Independent System Operator		X								
37.	Individual	David Kiguel	Hydro One Networks Inc.	X		X							
38.	Individual	Jason Marshall	Midwest ISO		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
39.	Individual	Claudiu Cadar	GDS Associates Inc.	X									
40.	Individual	Chifong Thomas	Pacific Gas and Electric Co.	X		X		X					
41.	Individual	Catherine Koch	Puget Sound Energy	X									
42.	Individual	Harold Wyble	Kansas City Power & Light	X		X		X	X				

1. **The SDT is proposing a revision to footnote 'b' in the TPL tables to comply with FERC Orders which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.**

Summary Consideration: Industry response was divided in relation to support for the proposed footnote 'b' which was posted for an informal comment period through October 8, 2010. Although there were a number of supporters for the proposed footnote they were outnumbered by the commenters who did not support the footnote text and offered their views and concerns.

The Standard Drafting Team (SDT) carefully considered the feedback provided and has made clarifying revisions to the footnote 'b' text. For each major item, the SDT has addressed the issue raised and has summarized any revision made to footnote 'b' in response to the feedback provided. The SDT appreciates industry input and believes the changes made are responsive to the comments received.

Open and Transparent Process: Most of the comments received related to the use of an "open and transparent" stakeholder process as described in the proposed footnote 'b'. While the comments on this topic varied, the majority of comments indicated that such a process should not be included within a mandatory Reliability Standard and cited that FERC Order 890 already requires the sharing of planning information. Others indicated that the statement for "review and acceptance" exceeds expectations required by FERC Order 890 and that an entity's compliance to a Reliability Standard should not be subject to the "acceptance" of stakeholders and that a process conforming with FERC Order 890 principles already requires dispute resolution. Some commenters expressed support of the process and it is noted that those who responded "Yes" with no comment were assumed to support the process "as is".

The SDT's inclusion of a stakeholder review in footnote 'b' was driven by the fact that FERC Order 890 does not fully cover the continent-wide footprint addressed by a NERC Reliability Standard. Additionally, footnote 'b' is being applied to address localized Bulk Electric System performance and not a wide-area Bulk Electric System concern that is generally the focus of the "open and transparent" process governed by FERC Order 890.

The SDT thoroughly considered all comments on the stakeholder process model. The SDT continues to support a Reliability Standard providing mandatory enforcement utilizing a stakeholder process where any intended use of planned Demand interruption has transparency and that stakeholders have the opportunity to comment on its use. However, upon further reflection the majority of SDT members agreed that including the "acceptance" aspect of the stakeholder process presents challenges within the context of a Reliability Standard and "acceptance" has been removed. The SDT agrees with opinions that an entity's compliance should not be subject to the "acceptance" of its plans by stakeholders. Also, the SDT realizes that for most entities there is a final, high level review with acceptance or approval of Transmission plans at the local level. So, while the footnote no longer references the need for stakeholder acceptance, the expectation is that there will be a review process in place that will consider the implementation of any plan calling for Demand interruption as explained in the footnote.

In addition, the SDT has revised footnote 'b' to explicitly require a response to any challenges presented via the stakeholder process.

Demand vs. Load: Several commenters questioned the SDT's use of the term "Demand" instead of "Load" in the proposed footnote. The SDT clarifies that this was intentional as the existing, approved TPL suite of standards uses the term Demand throughout the requirement text. Additionally, the existing, approved TPL performance requirements documented in Table I contain the column heading "Loss of Demand or Curtailed Firm Transfers" which is the subject of the footnote 'b' applicability for category B (single element) Contingencies. This project, Project 2010-11, aims to address footnote 'b' regulatory directives with no change to the remainder of the standard. Therefore, for consistency with the existing standard text, the term Demand is retained.

Firm transfer vs. Firm Transmission Service: Some stakeholders suggested that the SDT revert back to the use of "Firm Transmission Service" instead of the undefined term "firm transfers." The SDT clarifies that that the change to "firm transfers" was intentional as the existing, approved TPL suite of standards references "firm transfers" both in requirement text and Table I. The existing, approved TPL performance requirements documented in Table I contain the column heading "Loss of Demand or Curtailed Firm Transfers" which is the subject of the footnote 'b' applicability for category B (single element) Contingencies. This project, Project 2010-11, aims to address footnote 'b' regulatory directives with no change to the remainder of the standard. Therefore for consistency with the existing standard text, the term 'firm transfer' is retained.

Amount of Demand Loss: The majority of commenters agree with the SDT's clarifications regarding interruption of Demand as defined in the proposed footnote 'b'. The majority of entities who commented support the limited use of Demand interruption and that when used to address a BES performance requirement agree that it should be documented, and made known through a stakeholder process. However, as stated above, the majority stopped short of supporting a mandatory Reliability Standard requiring "acceptance" by other entities for the planned interruption of Demand.

Other minority views propose to limit or cap the amount of Demand loss and some suggested 50 MW as the appropriate level. Some felt the SDT’s prior approach of limiting the Demand loss to only “radial” line configurations was appropriate and superior to the “open process” approach. It is also noted that some commenters went further to say no loss of Demand should be allowed for a single Contingency, but this was clearly a minority view of the comments submitted.

The SDT carefully considered the comments and unanimously agreed that defining a Demand level limit is problematic based on the vast differences in BES applications across the continent and that each potential use is case specific. The SDT also had concerns that setting such a limit may have the unintended consequences of planned Demand interruption being more widely accepted in practice in Transmission planning. The SDT and most commenters are of the opinion that a stakeholder review process is a better deterrent for Demand interruption and will appropriately guard against any misuse.

The revised footnote ‘b’ is:

b) An objective of the planning process ~~is to avoid~~ should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. ~~Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process~~. However, it is recognized that Demand ~~may need to~~ will be interrupted if it is directly served by the elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- ~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~
- Interruptible Demand or Demand-Side Management
- ~~Demand that does not adversely impact overall BES reliability where the c~~Circumstances ~~describing~~ where the use of ~~such~~ Demand interruption are documented, including alternatives evaluated; and where the ~~application~~ Demand interruption is subject to review ~~and acceptance~~ in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	1. The introductory paragraph discourages the Interruption of any Demand, implying that no Demand directly connected should be interrupted. However, it is an acceptable practice to allow for some Interruption of Demand that is directly connected to the element that is removed from service. Recommend that the drafting team revise the wording to eliminate this implication, and soften the expectation such that it is recognized that some Interruption of Demand is unavoidable by system configuration, but that each entity should establish a reasonable limit on how much demand can be interrupted due to the loss of an element. 2. The Statement that “However, Demand may need to be interrupted in limited circumstances to address BES performance requirements” in the introductory paragraph contradicts bullet 3 “Demand that does not adversely affect BES ...” 3. The third Bullet is confusing. Suggest revising the wording to clarify the adverse impact to the BES system, documentation expectations, and to answer fundamental questions such as who has the authority to decide the use if the stakeholder process is “accepting”, and the necessity of having a stakeholder process. It is unlikely that the interruption of Demand will adversely impact the BES system. This constraint is too broad. The language in this bullet also allows that non-consequential Demand interruption could be used to mitigate reliability violations arising from the NERC Category B contingency events (i.e., single element contingencies). 4. In the second paragraph, the conditions when interruption of Firm Transfers may be used are not specified. 5. In the last sentence of the second paragraph, “would” should be replaced by “must”. Alternatively, possible rewording of footnote “b” to be considered: b) An objective of the planning process should be to minimize the likelihood of interrupting Demand and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements or other local reasons which have no adverse impact on overall BES reliability or the interconnected BES. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Demand that does not adversely impact overall reliability of the BES or the interconnected BES and where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of available resources, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected. The Drafting Team should reconsider the use of “Load” as opposed to “Demand”. By definition (NERC

Organization	Yes or No	Question 1 Comment
		Glossary dated April 20, 2010) Demand is:"1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer."Load is defined as:"An end-use device or customer that receives power from the electric system."This terminology is more appropriate to the application used in the Table.
Hydro One Networks Inc.	No	1. The introductory paragraph discourages the Interruption of any Demand, implying that no Demand directly connected should be interrupted. However, it is an acceptable practice to allow for some Interruption of Demand that is directly connected to the element that is removed from service. Recommend that the drafting team revise the wording to eliminate this implication, and soften the expectation such that it is recognized that some Interruption of Demand is unavoidable by system configuration, but that each entity should establish a reasonable limit on how much demand can be interrupted due to the loss of an element. 2. The Statement that "However, Demand may need to be interrupted in limited circumstances to address BES performance requirements" in the introductory paragraph contradicts bullet 3 "Demand that does not adversely affect BES ..." 3. The third Bullet is confusing. Suggest revising the wording to clarify the adverse impact to the BES system, documentation expectations, and to answer fundamental questions such as who has the authority to decide the use if the stakeholder process is "accepting", and the necessity of having a stakeholder process. It is unlikely that the interruption of Demand will adversely impact the BES system. This constraint is too broad. The language in this bullet also allows that non-consequential Demand interruption could be used to mitigate reliability violations arising from the NERC Category B contingency events (i.e., single element contingencies). 4. In the second paragraph, the conditions when interruption of Firm Transfers may be used are not specified. 5. In the last sentence of the second paragraph, "would" should be replaced by "must". Alternatively, possible rewording of footnote "b" to be considered: b) An objective of the planning process should be to minimize the likelihood of interrupting Demand and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements or other local reasons which have no adverse impact on overall BES reliability or the interconnected BES. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Demand that does not adversely impact overall reliability of the BES or the interconnected BES and where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of available resources, where it can be demonstrated that Facilities remain within

Organization	Yes or No	Question 1 Comment
		applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected. The Drafting Team should reconsider the use of “Load” as opposed to “Demand”. By definition (NERC Glossary dated April 20, 2010) Demand is:”1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.”Load is defined as:”An end-use device or customer that receives power from the electric system.”This terminology is more appropriate to the application used in the Table.
SERC Planning Standards Subcommittee	No	The revised text relating to the planning process exceeds what is appropriate for a reliability standard. Existing open and transparent stakeholder processes focus on larger system issues and not on local load serving. We suggest the following: Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Interruptible Demand or Demand-Side Management o Demand that does not adversely impact overall BES reliability and is made temporarily radial as a result of the Contingency, where that Demand must be interrupted to meet performance requirements. Curtailment of firm transfers is allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected. “ The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.”
Ameren	No	The revised text to footnote b relating to the planning process exceeds what is appropriate for a reliability standard. Existing open and transparent stakeholder processes focus on larger system issues rather than on local load serving issues. We suggest the following text for footnote b:Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Interruptible Demand or Demand-Side Management o Demand that does not adversely impact overall BES reliability and is made temporarily radial as a result of the Contingency, where that Demand must be interrupted to meet performance requirements. Curtailment of firm transfers is allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the

Organization	Yes or No	Question 1 Comment
		re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.
MRO's NERC Standards Review Subcommittee	No	The revised draft is a significant improvement over the first draft. However, we suggest the following minor changes: 1. The criterion of "adversely affect overall BES reliability" is undefined and maybe subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest adding the words "as defined by each Transmission Planner or Planning Authority". 2. The term of "firm transfers" is undefined and maybe subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest establishing a definition for the term, reverting to the "Firm Transmission Service" term, or using another appropriate defined term.
American Transmission Company	No	The revised draft is a significant improvement over the first draft. However, we suggest the following minor changes: 1. The criterion of "adversely affect overall BES reliability" is undefined and may subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest adding the words "as defined by each Transmission Planner or Planning Authority". 2. The term of "firm transfers" is undefined and may subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest establishing a definition for the term of "firm transfers", reverting to the "Firm Transmission Service" term, or using another appropriate NERC defined term.
PacifiCorp	No	PacifiCorp believes that the current version of footnote "b" is an improvement over the language that currently exists in the standard, except for one component of the revised footnote. The third bullet in the draft standard currently limits the interruption of Demand if it does not adversely impact overall BES reliability, where the circumstances describing the use of the interruption are documented (including alternatives evaluated) and the application is subject to review and acceptance in "an open and transparent stakeholder process." PacifiCorp believes that the language requiring review and acceptance of an application of demand interruption through any sort of stakeholder process should be removed. It is not practical or effective to prescribe that either this standard or any other standard requires stakeholder approval in order to maintain compliance. As presently drafted, this requirement for stakeholder review and acceptance appears to be inconclusive and indeterminate as to what is required for registered entities to comply. Instead, this third bullet should require the documentation, by the Planning Authority and Transmission Planner, of the circumstances describing the use of Demand interruption - including methodologies used, assumptions relied upon, and alternatives evaluated - as part of the Planning Authorities' and/or Transmission Planners'

Organization	Yes or No	Question 1 Comment
		documentation of results in their annual Reliability Assessments. These annual assessments are already submitted to the appropriate Regional Reliability Organization pursuant to TPL-002-1b Requirement R3. This annual assessment can be provided by the ERO to other appropriate third parties upon their request.
Southern Company	No	The revised text relating to the planning process exceeds what is appropriate for a reliability standard. Existing open and transparent stakeholder processes focus on larger system issues and not on local load serving. We suggest that the drafting team go back to the concept of local load being the load that is made temporarily radial by the contingency. That was a much better approach.
JEA	No	The requirement in general is acceptable; however, there needs to be an added "such as" clause to the referenced "...in an open and transparent stakeholder processes." I suggest adding "..."...in an open and transparent stakeholder processes such as the FERC approved regional 890 process that includes the load serving entity affected".
South Carolina Electric and Gas	No	SCE&G believes the first sentence "An object of the planning process is to avoid interruption of Demand." goes beyond what is appropriate for a reliability standard and therefore should be deleted. Also, the part of the sentence that states "and where the application is subject to review and acceptance in an open and transparent stakeholder process" goes beyond what is appropriate for a reliability standard and should be deleted.
NorthWestern Energy	No	In addition to the three bullet items, add a fourth bullet item to the list of limitations under the body of footnote b: "In no case will a total loss of load that is less than 50 MW be considered a violation of this standard."
TVA Transmission Planning & Compliance	No	TVA supports FERC's actions on improving reliability of the BES; however, TVA believes that the new proposal is focusing more on reliability of local loads than on the overall reliability of the BES. Footnote b should focus only on the overall reliability of the BES. Reliability of local loads should be addressed outside the TPL standards and therefore should not be used/referenced in footnote b. Also existing stakeholder processes (referred to in the SDT proposal) typically focus on larger system issues and not on local load serving. Thus TVA believes that some local load should be allowed to be dropped in order to maintain BES reliability. However TVA does believe that there should be a limit of how much load can be dropped in order to maintain BES reliability. TVA believes that 50 MW is a reasonable number for this limit. Based on the above, TVA proposes substituting the following for the revised footnote b:Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: Demand that is directly served by the elements that are removed from service as a result of the Contingency Interruptible Demand or Demand-Side Management Demand that does not adversely impact overall BES reliability, where that Demand (not to exceed 50 MW)

Organization	Yes or No	Question 1 Comment
		must be interrupted to meet performance requirements. Curtailment of firm transfers is allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.
BC Hydro	No	The SDT is to be commended for their efforts to develop clear, unambiguous language for Footnote "b". From the discussions that have taken place it seems that there are many different perspectives and to get agreement on specific language will be very difficult. We believe that it would be useful to identify the main issues that Footnote "b" needs to address and we consider those main issues to be: o Definitions of (a) Consequential Load Loss, (b) Firm Demand, (c) Firm Transmission Capability (as distinct from the OATT term, "Firm Transmission Service"), (d) Firm Transfer (this could be defined as transfers using the OATT's Firm Transmission Service, (e) Manual System Adjustments (capitalized in the Category C section of TPL-001, but not defined in the NERC Glossary) and (f) the Bulk Electric System (BES). o Identifying permissible Demand/Transfer curtailment actions for (a) the planning studies simulating the Category B event itself and (b) the planning studies associated with determining acceptable actions for preparing for the next set of contingencies should the initial single contingency be prolonged (ie, last several weeks). This would define the acceptable (pre-emptive) "Manual System Adjustments" of Category C events. o Define separate acceptable curtailment actions for (a) curtailment of Demand (ie, end-user load) and (b) curtailment of market to market transfers, that very rarely, if ever, result in the loss of any end-user load. o Define the planning studies required to determine the acceptability of the impacts on the BES resulting from curtailments in a "remote" part of the system that have been accepted by those directly affected by those curtailments. At this point we don't have specific language to suggest, but we do have the following comments that we hope will help: A. Interruption of Demand: A.1. Consider improving the definition of "Firm Demand" in the NERC Glossary that now reads, "That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions". Perhaps it could be changed to something like, "That portion of the Demand that the planned transmission system must be able to supply without interruption for Category B events. A.2. Consider stating in Footnote "b" that curtailment of Firm Demand is (a) not permitted in the simulation of the N-1 event itself and (b) it is not permitted as part of the (pre-emptive) "Manual System Adjustments" needed to prepare for the next set of contingencies should the initial single contingency be prolonged (ie, last

Organization	Yes or No	Question 1 Comment
		several weeks). B. Interruption of Firm Transfers: B.1. “Firm Transfers” could be defined as transfers using the OATT’s Firm Transmission Service, but consider developing a system reliability-based term for “Firm Transmission Capability” instead of referring to the tariff-based NERC definition of “Firm Transmission Service”. This would recognize the difference between planning standards and commercial/tariff rules. The NERC definition of “Firm Transmission Service” is now, “The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption”. Transmission tariffs address the priority of curtailments when the loading on a transmission path needs to be reduced for whatever reason (single- or multiple-contingencies). The NERC transmission planning standards need a system reliability definition like, “Firm Transmission Capability” is the transmission capability across a cut-plane, on a defined transmission path or across a defined flowgate that is available, before any manual corrective actions are taken, following the worst Category B event under the most onerous normal system conditions considering all plausible generation dispatch patterns and the full range of expected load levels.” B.2. Consider stating in Footnote “b” that curtailment of Firm Transfers is only permitted to the extent that redispatch of generation can be implemented so that delivery to the Firm Transfer recipient is not interrupted (a) in the planning studies of the Category B event itself and (b) as part of the (pre-emptive) “Manual System Adjustments” needed to prepare for the next set of contingencies should the initial single contingency be prolonged (ie, last several weeks). C. General Comments: C.1. Consider replacing the first bullet of the proposed Footnote “b” with simply “Consequential Load Loss” since the NERC Project 2006 02 (TPL 001) Standard Drafting Team is introducing the following definition: Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault C.2. Consider removing “Demand-Side Management” (DSM) from the second bullet because that term is too general. The present definition of DSM in the NERC Glossary is:”The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use”. C.3. Consider being more specific on what constitutes acceptable “Interruptible Demand”, like: “Interruptible Demand that is part of an automatic real-time Direct Control Load Management (DCLM) system that is activated by the contingencies that require it and that is a completely “dual-redundant” scheme including all communications equipment. The DCLM system must result in automatic curtailment of Demand that is fast enough to maintain all BES system performance standards (eg, voltage stability, voltage dip, etc)”.

Organization	Yes or No	Question 1 Comment
		C.4. Consider eliminating the description of how interrupting Demand that does not adversely impact overall BES reliability was accepted (ie, the stakeholder process, etc). If such a process were undertaken and it resulted in acceptance that the Demand could be curtailed for Category B events, wouldn’t that simply mean that the Demand was “Interruptible Demand”. It really doesn’t matter what process resulted in it being accepted. The key considerations are that (a) if the interruption of that Demand is necessary to maintain BES reliability, then it must be interrupted in a very reliable manner (ie, dual redundant scheme, etc) and (b) if the interruption of that Demand is not necessary to maintain the reliable performance of the BES, then that should be confirmed by the planning studies (ie, it doesn’t need to have an expensive, sophisticated, dual-redundant DCLM scheme since the impact on the BES is acceptable even if the scheme doesn’t work). D. Additional Questions related to Curtailment of Firm Transfers: In the past, the latter part of Footnote B read: “To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.”The last part of the proposed Footnote B now reads: “Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected.”We would like to understand the implications of the proposed Footnote B as it relates to curtailment of Firm Transfers (as per definition proposed earlier) for the following questions: 1) In the most recent draft of Footnote B, why was the NERC defined term ‘Firm Transmission Service’ replaced with the non-defined term ‘firm transfers’? 2) In the most recent draft of Footnote B, why was the tone softened from “No curtailment of Firm Transmission Service is allowed, except...” to “Curtailment of firm transfers is allowed when...”? 3) Assuming an outage of a single transmission line (N-1 Category B event) has occurred and assuming that no “resources [are] obligated to redispatch” for this outage, would a transmission provider be allowed to curtail Firm Transmission Service (NERC defined term) that it has sold in order to prepare to withstand the next worst credible contingency? 4) Would transmission providers be allowed to sell Firm Transmission Service on a path above what could be delivered with any one element of that path out of service and a range of operating conditions? 5) If the proposed Footnote B is approved, would utilities have to reinforce their system (within 60 months) to ensure that Firm Transmission Service for particular paths would not be curtailed can be delivered when any one element of that path is out of service? 6) If a transmission provider employs Generation Dropping for single contingencies in order to support Firm Transmission Service between regions, and assuming there are no provisions for obligated re-dispatch, would

Organization	Yes or No	Question 1 Comment
		the proposed Footnote B force a recalculation of firm vs non-firm transfer capability? 7) Path 66 (PACI) and Path 65 (PDCI) can both see significant derates in their firm transfer capability for single contingencies. How would the proposed Footnote B impact Firm Transmission on these paths?
FirstEnergy	No	FirstEnergy appreciates the efforts of the Assess Transmission Future Needs SDT in reaching a reasonable proposal for clarifying Table 1 footnote B presented in the TPL-001 through TPL-004 standards. We also commend NERC staff for convening an industry technical conference to discuss the topic and FERC staff for their participation in the technical conference as the industry carefully considered various perspectives. The proposed footnote B is much improved from the prior draft proposals. One change that FirstEnergy proposes is to strike the text following the semicolon in the third bullet item which states "and where the application is subject to review and acceptance in an open and transparent stakeholder process." This text may be intended as explanatory but has the appearance of mandating an approval process that will be auditable through the TPL reliability standards. The statement is not needed within the framework of mandatory reliability requirements as FERC Order 890 already mandates an open and transparent process related to the planning of the bulk electric system. FERC via the 890 Final Rule modified the pro forma Open-Access Transmission Tariff to require open and transparent stakeholder process to better ensure no undue discrimination and access to the transmission system. The Final Rule beginning at paragraph 418 discusses reform to the Coordinated, Open and Transparent Planning of the transmission system. The Commission direction included eight planning principles required to be within the open process - one of which is dispute resolution. It should be well understood that the transmission planner and planning coordinator share and disseminate all of their planning study results and proposed corrective actions - including the proposed use of Demand interruption - as part of their adherence to Order 890. We appreciate the SDT's careful consideration of our comments.
Northeast Utilities	No	NU agrees with the language of the proposed revision to Footnote b EXCEPT FOR bullet #3 which suggests that non-consequential demand interruption could be used to mitigate reliability violations arising from the NERC Category B contingency events (i.e., single element contingencies).
ERCOT	No	The introductory paragraph of footnote b includes policy language. Since this is a reliability standard-and not a policy directive-the general narrative setting forth the desired policy goal of minimizing load-shedding is misplaced. Including policy language can cloud the specific issues the standard attempts to address, and ERCOT recommends deleting the first two sentences in the introductory paragraph. The next sentence in the introductory paragraph goes on to state, generally, that demand may be interrupted to "address BES performance requirements." This phrase is vague. To which performance requirements does this refer? The intent is not clear. If the intent is to generally recognize the need to shed load to respect

Organization	Yes or No	Question 1 Comment
		NERC standards and to allow flexibility for an entity to exercise discretion relative to meeting BES performance requirements, then that intent should be clearly reflected in the language. Furthermore, the last sentence of the introductory paragraph and the subsequent bullet points are arguably inconsistent with this approach, because they could be viewed as removing an entity’s flexibility/discretion by limiting the circumstances when load can be shed. The second bullet point is unnecessary, because it is already apparent that interruptible demand/demand side management programs can be used according to their terms. This could create confusion in that it could be implied that, absent the need to use these to meet BES performance requirements, using them otherwise is inconsistent with/not allowed under footnote b. Simply put, those products are not load shedding as contemplated by this footnote. Therefore they should not be listed here. With respect to the third bullet point, the phrase "demand that does not adversely impact overall BES reliability" is not adequately defined, and provides opportunity for confusion. This is an ambiguous phrase and can’t be linked back to objective NERC standards/requirements. The bullet points should avoid ambiguity to mitigate ambiguity risk in audits. In addition, the last part of the language in this bullet imposing an open and transparent stakeholder process is unclear. What is the intent behind requiring review in a stakeholder process? If it is to establish the ability of the entity to develop load shedding procedures beyond those explicitly contemplated in footnote b, ERCOT questions if it is reasonable for the responsible entity to be required to get “permission” from stakeholders to implement reliability measures related to its obligation as the functional entity. Again, the language simply is not clear. Accordingly, ERCOT recommends this bullet point be removed. If it is retained, it should be revised consistent with these comments to remove ambiguous language to mitigate potential confusion around the meaning/scope of the footnote in the administration of the CMEP. In addition, ERCOT recommends revising the draft footnote b to allow for planned Demand interruption as a means of mitigation during interim periods when a unanticipated (such as unexpected demand growth or unit retirements) or temporary change on the system occurs in a timeframe that is shorter than the time necessary to plan and implement the system upgrades necessary to avoid the Demand interruption. Finally, in the last paragraph of footnote b, it isn’t clear why “Transmission Service” was changed to “transfers.” Firm transmission service is a service provided in some regions, and it provides relative value to other types of services-e.g., non-firm and network. The mention of transmission service may also be irrelevant in this footnote, since the allowance of its interruption doesn't also allow for load shedding. Therefore, ERCOT recommends eliminating the last paragraph of footnote b.
ISO New England Inc.	No	ISO New England does not allow non-consequential load loss for first contingencies in Planning Analysis, and as an overall matter, ISO-NE believes that the appropriate step is for NERC to modify the footnote in line with

Organization	Yes or No	Question 1 Comment
		the original FERC Order. However, ISO-NE offers the following recommendation to improve the proposed language for footnote b if it is to be retained similar to what has been proposed. In short, ISO-NE proposes changing the third sub-bullet, because the provision is both unnecessary and inappropriate for a NERC Standard. First, the sub-bullet is redundant, because the Commission has ordered that companies add to their Open Access Transmission Tariffs an open and transparent planning process. If Transmission Planners establish their system planning assessments through those processes, then there should be no question that the Planner’s assessments have been effectively communicated to the region. Second, the passive nature of the language (i.e., “where the application is subject to review and acceptance...”) is unclear as it suggests that someone other than the Planning Coordinator/Transmission Planner is responsible for determining what belongs in a long-term system assessment. Including Demand-Side Management in the standard also appears redundant as Demand Response is used as an asset in the same manner as generation resources. b) When interruption of Demand is utilized within the planning process, such interruption is limited to: 1) Demand that is directly served by the elements that are removed from service as a result of the Contingency. 2) Interruptible Demand or Demand-Side Management 3) Instances where the planned or controlled interruption of Demand results in System performance which meets the requirements of Table 1 for Category B contingencies. When such Demand interruption is utilized in an assessment, the use of such actions must be limited to small portions of the system, be operationally achievable, be of limited duration, and be documented therein.
Entergy Services	No	Entergy disagrees with the proposed language in the third bullet for two reasons. 1. While Entergy supports the idea of “an open and transparent stakeholder process” regarding the use of non-consequential load loss. It is unclear how such a process could be fairly implemented as competing stakeholder interests could prevent resolution. Stakeholders should be defined as those stakeholders whose load could be shed per footnote b, not any and all stakeholders. 2. The “is subject to review and acceptance” implies that some formal voting process would be required by stakeholders. Is this the SDT’s intent? If so would such a process be developed as part of the standard or would it be left up to TO’s? If non-consequential load loss was deemed an acceptable solution across a SEAM, would the TO’s jointly serving the load need to agree?

Organization	Yes or No	Question 1 Comment
MidAmerican Energy	No	While the TPL note "b" approach has improved, MidAmerican has concerns that including the wording "review and acceptance" goes beyond the FERC Order 890 order, process, and intent of including the open review process. Therefore, to align with FERC Order 890, the "review and acceptance" should be replaced with "subject to comment". Anything more exceeds FERC Order 890 and the reason why the review process was included. In the end, Transmission Owning and Operating entities must have final say in the operation of the grid. Entities can comment, but cannot obstruct Transmission Owning and Operating entities from properly operating the grid or reliability could be reduced.
United Illuminating Co	No	United Illuminating believes that for TPL Category B contingencies no planned or controlled (non-consequential) interruption of firm demand should occur as a general philosophy for planning the Bulk Electric System (BES). Recognizing there are certain areas of the BES that have unique circumstances that may warrant an exception to this, UI suggests the addition of language that recognizes the limited application of non-consequential load interruption with a process that requires a case-by-case acceptance of such application by the Regional Entity or NERC.
New York Independent System Operator	Yes	The NYISO agrees in principle with the proposed changes, but recommends the following modifications: 1. The introductory paragraph discourages the Interruption of any Demand, implying that no Demand directly connected should be interrupted. However, it is an acceptable practice to allow for some Interruption of Demand that is directly connected to the element that is removed from service. The introductory paragraph is immaterial to the requirement, and therefore unnecessary with the exception of the last sentence which starts the bulleted list. 2. Interruptible demand is an operation tool and not a transmission planning tool, while Demand-Side Management is typically embedded in the load forecast used in the planning process. The second bullet therefore may not be necessary or applicable here, though it is helpful in making clear those are acceptable forms of interruption. 3. The third bullet is confusing. Suggest revising the wording to clarify the adverse impact to the BES system and documentation expectations. Recommend removing reference to the application being subject to review and acceptance in an open and transparent stakeholder process; this is inherent to all documentation and does not need to be emphasized in a footnote. 4. In the last sentence of the last paragraph, "would" should be replaced by "must". 5. The Drafting Team should reconsider the use of "Load" as opposed to "Demand". By definition (NERC Glossary dated April 20, 2010) Demand is: 1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer."Load is defined as:"An

Organization	Yes or No	Question 1 Comment
		end-use device or customer that receives power from the electric system."This terminology is more appropriate to the application used in the Table. Possible rewording of footnote "b" to be considered: b) Under the limited circumstances when interruption of Load is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Load that is directly served by the elements that are removed from service as a result of the Contingency o Interruptible Load or Demand-Side Management o Demand that does not adversely impact overall BES reliability where the circumstances for the use of such Load interruption and alternatives evaluated are documented. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of available resources, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be respected.
Midwest ISO	No	Overall, we believe the changes are reasonable. However, we propose to strike "and where the application is subject to review and acceptance in an open and transparent stakeholder process." Stakeholder review processes should not be mandated through enforceable standards as they do not provide a clear benefit to reliability. Further, FERC Order 890 already mandates an open and transparent process related to the planning of the bulk electric system.
GDS Associates Inc.	No	We appreciate all the work conducted by SDT to adjust current footnote "b" however, we disagree with the current approach as follows below:- The definition does not go far enough with recognition that interruption of Demand should be mitigated if at all possible. The previous language may have been inadequate, but the current language does not encourage the TP to develop mitigation plans that could be implemented as an alternative to Demand interruption. - Use of Interruptible Demand should only be implemented if the Transmission Planner can point to a contract between the Transmission Provider and Transmission Customer that permits load curtailment .- Under FERC Order 890, Conditional Firm transmission service can be granted for entities who voluntarily acknowledge the right of the Transmission Provider to curtail their transaction or provide re-dispatch. This should be the only transfer which can be utilized in the Planning Horizon for interruption of Demand for Note b. Suggested language to find the balance point in the tone of this note is below:"An objective of the planning process is to develop mitigation plans that do not call for the curtailment of Demand, as interruption of Demand places specific customer groups at a reliability risk that varies from their counterparts in other areas of the BES. There may be rare instances, however, where interruption of Demand can be considered a short-term bridge to a mitigation plan which does not rely on negatively impacting certain customer segments. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency, o

Organization	Yes or No	Question 1 Comment
		Interruptible Demand or Demand-Side Management, where the Customer has given explicit rights to the Transmission Provider for curtailment of their Demand, o Demand, other than Interruptible Demand or Demand-Side Management, that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand are documented, including alternatives evaluated; where the Load-Serving Entity who has responsibility for serving such Demand has agreed to the curtailment, and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of Firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch per the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of and firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected. In addition, any Conditional Firm transfers may be curtailed, in accordance with the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider."
Kansas City Power & Light	No	KCPL appreciates the efforts of the Assess Transmission Future Needs SDT in reaching a reasonable proposal for clarifying Table 1 footnote B presented in the TPL-001 through TPL-004 standards. We also commend NERC staff for convening an industry technical conference to discuss the topic and FERC staff for their participation in the technical conference as the industry carefully considered various perspectives. Although the proposed footnote B is much improved from the prior draft proposals, KCPL proposes is to strike the text following the semicolon in the third bullet item which states "and where the application is subject to review and acceptance in an open and transparent stakeholder process." This text may be intended as explanatory but has the appearance of mandating an approval process that will be auditable through the TPL reliability standards. The statement is not needed within the framework of mandatory reliability requirements as FERC Order 890 already mandates an open and transparent process related to the planning of the bulk electric system. FERC via the 890 Final Rule modified the pro forma Open-Access Transmission Tariff to require open and transparent stakeholder process to better ensure no undue discrimination and access to the transmission system. The Final Rule beginning at paragraph 418 discusses reform to the Coordinated, Open and Transparent Planning of the transmission system. The Commission direction included eight planning principles required to be within the open process - one of which is dispute resolution. It should be well understood that the transmission planner and planning coordinator share and disseminate all of their planning study results and proposed corrective actions - including the proposed use of Demand interruption - as part of their adherence to Order 890.
Puget Sound Energy	Yes	PSE agrees with the foot note b as stated. As it states for any category B outage there wouldn't be any non-consequential load loss allowed unless a full study is performed with evaluation of alternatives and is approved by stakeholders. Also, one could curtail firm transfers if re-dispatch of resource is possible.

Organization	Yes or No	Question 1 Comment
		However, there is still some ambiguity in when approval from stakeholders (time-line) should be sought and who the stakeholders could be (customers, effected utilities etc.). Hence, PSE would like to revise the footnote by adding the following to the end of the footnote, ".... at least 2 years prior to the implementation. All the affected parties must review and agree upon the loss of demand proposal."
Southern California Edison Company	Yes	SCE appreciates the efforts of the NERC Standards Drafting Team and believes that the team has admirably worked to meet FERC's expectations.SCE would suggest that Footnote "b" be revised to include a semi-colon(;) after the first sub-paragraph and a semi-colon(;) followed by an "and" after the second sub-paragraph, to convey that the three sub-paragraphs are alternative, rather than additive methods for satisfying the requirements for "interruptions."
Idaho Power	Yes	footnote 'b' is silent with respect to planned removal from service of certain generators. I believe there are many conditions out there where a single contingency can initiate a planned (RAS-initiated) removal of generation. The fact that this is mentioned in footnote 'c', under multiple contingencies, begs the need for futher elaboration/discussion of this option under single contingencies in footnote 'b'.
Manitoba Hydro	Yes	The changes to Table 1 Note b proposed by the SDT for this second posting are a reasonable approach to the issue of interrupting of “Firm Demand”. The requirement to evaluate alternatives to dropping of Firm Demand in a transparent stakeholder process should provide the verification of cost over benefit on a case by case basis. I propose the following editorial changes: 1. The change of “Firm Transmission Services” made in Table 1 should be also be made in each TPL standard as R1 refers to “projected Firm (non-recallable reserved) Transmission Services.2. Since “Firm Demand” is a defined term, ensure it is capitalized throughout the standard. There is one instance where it is not.
California ISO	Yes	1) Regarding the 2nd bullet provision, we suggest: Interruptible Demand or Demand-Side Management that has been reviewed and approved by the Planning Authority. 2) Regarding the 3rd bullet provision, we suggest: Demand interruption that does not adversely impact overall BES reliability.... 3) Also regarding the 3rd bullet provision, we suggest replacing acceptance with clarification to read “where the application is subject to review and clarification in an open and transparent stakeholder process."
Xcel Energy	Yes	Xcel Energy supports the new interpretation that would allow curtailment of firm transfers or demand for limited conditions where the integrity of bulk electric system is not compromised. However Xcel Energy seeks some clarification regarding the following: The 3rd bullet point in footnote b will need to clarify whether the demand interruption can be done after the contingency, or before the contingency. If it is allowed after the

Organization	Yes or No	Question 1 Comment
		contingency, then the standard would allow violation of voltage or thermal loading criteria for a brief period, after contingency and, before demand curtailment happens. Is this acceptable based on the new interpretation? Since TPL-002 standard deals with NERC Category B contingencies, and footnote b states that curtailment of firm transfers is allowed, it should be clarified if this curtailment is allowed before or after the contingency. If the curtailment is allowed only after the contingency, then the system would be in violation of the thermal or voltage criteria for a brief period till the generation is re-dispatched. Is this allowed by the new interpretation? If curtailment is only allowed in preparation of the contingency, then the firm transfers would be curtailed during system intact conditions, in preparation for the first contingency, resulting in violation of TPL-001 standard. Is this allowed by the new interpretation?
PPL Corp	Yes	PPL believes that Footnote b as described in TPL-002-1b, Draft 2, August 30, 2010 is fine provided an accompanying Requirement (with appropriate VRF and VSL) and Measure is added to the TPL standard(s) to require and document notification of the affected Demand parties and the involvement of the affected Demand parties in an open process as described by Footnote b, third bullet.
Duke Energy	Yes	Duke Energy strongly supports this revised footnote ‘b’. We believe that it provides for appropriate consideration of stakeholder input in decision-making for local reliability issues, while maintaining the reliability of the Bulk Electric System.
ITC	Yes	The proposed language for the new TPL-001-1 Table 1 footnote b is acceptable to ITC.
Bonneville Power Administration	Yes	
Dominion	Yes	
IRS Standards Review Committee	Yes	
IRC Standards Review Committee	Yes	
Arizona Public Service Company	Yes	
ERCOT ISO	Yes	

Organization	Yes or No	Question 1 Comment
Georgia Transmission Corporation	Yes	
American Electric Power	Yes	
Independent Electricity System Operator	Yes	
Pacific Gas and Electric Co.	Yes	

Implementation Plan for Project 2010-11: TPL Table 1 Order

Prerequisite Approvals

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

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed standards.

Compliance with Standards

Standards	Functions That Must Comply With the Associated Requirements	
	Transmission Planner	Planning Authority
TPL-001-0.2: System Performance Under Normal (No Contingency) Conditions (Category A) TPL-002-0c: System Performance Following Loss of a Single Bulk Electric System Element (Category B) TPL-003-0b: System Performance Following Loss of Two or More Bulk Electric System Elements (Category C) TPL-004-0a: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

The effective date for footnote 'b' will be the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption.

All other requirements remain in effect as per previous approvals.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Informal comment period completed October 8, 2010.

Proposed Action Plan and Description of Current Draft:

This is the third draft of the proposed modification to footnote 'b' posted for a 45-day formal comment period, with an initial ballot to be conducted during the last 10 days of the comment period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Initial ballot	December 2010
2. Recirculation ballot	January 2011
3. Submit to BOT for approval	January 2011
4. File with FERC	February 2011

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-1

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-1_R1 and TPL-001-1_ R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Compliance Monitor: Regional Reliability Organization.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame
Annually

1.3. Data Retention
None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	 No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

  - Interruptible Demand or Demand-Side Management
  - Circumstances where the uses of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

  Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is

due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. Title: System Performance Under Normal (No Contingency) Conditions (Category A)

2. Number: TPL-001-1

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-1_R1 and TPL-001-1_ R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
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A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process ~~is to avoid~~ should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. ~~Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process~~. However, it is recognized that Demand ~~may need to~~ will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- ~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~
- Interruptible Demand or Demand-Side Management
- ~~Demand that does not adversely impact overall BES reliability where the c~~Circumstances ~~describing~~ where the uses of ~~such~~ Demand interruption are documented, including alternatives evaluated; and where the ~~application~~ Demand interruption is subject to review ~~and acceptance~~ in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)
2. **Number:** TPL-001-~~0~~1
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
   - **4.1.** Planning Authority
   - **4.2.** Transmission Planner

~~5. **Effective Date:** April 1, 2005~~

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-~~0~~1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-~~0 R2.~~1 R1 and TPL-001-~~0~~1 R2~~.2~~.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-~~0~~1 R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
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B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- Interruptible Demand or Demand-Side Management
- Circumstances where the uses of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Informal comment period completed October 8, 2010.

Proposed Action Plan and Description of Current Draft:

This is the third draft of the proposed modification to footnote 'b' posted for a 45-day formal comment period, with an initial ballot to be conducted during the last 10 days of the comment period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Initial ballot	December 2010
2. Recirculation ballot	January 2011
3. Submit to BOT for approval	January 2011
4. File with FERC	February 2011

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-1b

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- Interruptible Demand or Demand-Side Management
- Circumstances where the uses of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

A. Introduction

1. **Title:** **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. **Number:** TPL-002-1b

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process ~~is to avoid~~ should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. ~~Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process.~~ However, it is recognized that Demand ~~may need to~~ will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- o ~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~
- o Interruptible Demand or Demand-Side Management
- o ~~Demand that does not adversely impact overall BES reliability where the c~~Circumstances ~~describing~~ where the uses of ~~such~~ Demand interruption are documented, including alternatives evaluated; and where the ~~application~~ Demand interruption is subject to review ~~and acceptance~~ in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-~~0~~1b

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

~~**5. Effective Date:** April 1, 2005~~

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories~~,~~, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-~~0~~1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-~~0~~1_R1 and TPL-002-~~0~~1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-~~0~~1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- Interruptible Demand or Demand-Side Management
- Circumstances where the uses of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

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TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System

misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Informal comment period completed October 8, 2010.

Proposed Action Plan and Description of Current Draft:

This is the third draft of the proposed modification to footnote 'b' posted for a 45-day formal comment period, with an initial ballot to be conducted during the last 10 days of the comment period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Initial ballot	December 2010
2. Recirculation ballot	January 2011
3. Submit to BOT for approval	January 2011
4. File with FERC	February 2011

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-1a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-1_R1 and TPL-003-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
1a	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- Interruptible Demand or Demand-Side Management
- Circumstances where the uses of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-1a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-1_R1 and TPL-003-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
1a	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process ~~is to avoid~~ should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. ~~Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process.~~ However, it is recognized that Demand ~~may need to~~ will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements,, such interruption is limited to:

- ~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~
- Interruptible Demand or Demand-Side Management
- ~~Demand that does not adversely impact overall BES reliability where the c~~Circumstances ~~describing~~ where the uses of ~~such~~ Demand interruption are documented, including alternatives evaluated; and where the ~~application~~ Demand interruption is subject to review ~~and acceptance~~ in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

A. Introduction

1. **Title: System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-~~0~~1a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

~~**5. Effective Date:** April 1, 2005~~

5. **Effective Date:** The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-~~0~~1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-~~0~~1_R1 and TPL-003-~~0~~1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-~~0~~1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
1a	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	**Contingencies**	**System Limits or Impacts**		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	 No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- o Interruptible Demand or Demand-Side Management
- o Circumstances where the uses of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2
Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. **Number**: TPL-004-1

3. **Purpose**: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability**:

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- Interruptible Demand or Demand-Side Management
- Circumstances where the uses of such Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. Number: TPL-004-1

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority’s and Transmission Planner’s assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

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R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

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R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

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0	April 1, 2005	Effective Date	New
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	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

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b) An objective of the planning process ~~is to avoid~~ should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. ~~Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process.~~ However, it is recognized that Demand ~~may need to~~will be interrupted if it is directly served by the Elements removed from service as a result of the contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- ~~o Demand that is directly served by the elements that are removed from service as a result of the Contingency, or~~
- o Interruptible Demand or Demand-Side Management
- o ~~Demand that does not adversely impact overall BES reliability where the c~~Circumstances ~~describing~~ where the uses of such Demand interruption are documented, including alternatives evaluated; and where the ~~application~~ Demand interruption is subject to review ~~and acceptance~~ in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

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2. Number: TPL-004-~~0~~1

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4.2. Transmission Planner

~~**5. Effective Date:** April 1, 2005~~

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D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

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1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

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	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
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a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- Interruptible Demand or Demand-Side Management
- Circumstances where the uses of such Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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Unofficial Comment Form for TPL Table 1 Order (Project 2010-11)

Please **DO NOT** use this form to submit comments on the 3rd posting for Project 2010-11: TPL Table 1 Order. Please use the electronic comment form posted on the following project page:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

The electronic comment form must be completed by **January 5, 2011.** This is a 45-day formal comment period.

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information

The Standard Drafting Team (SDT) posted Table I, footnote 'b' for an informal comment period from September 8, 2010 through October 8, 2010. Industry response was divided in relation to support for the proposed footnote 'b.' Although there were a number of supporters for the proposed footnote they were outnumbered by the commenters who did not support the footnote text for various reasons and offered their views and concerns.

The SDT carefully considered the feedback provided including minority opinions such as not allowing Demand interruption at all and has made clarifying revisions to the footnote 'b' text.

The revisions made to footnote 'b' following the informal comment period are shown below:

b) An objective of the planning process ~~is to avoid~~ should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. ~~Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process~~. However, it is recognized that Demand ~~may need to~~ will be interrupted if it is directly served by the elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to:

- ~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~
- Interruptible Demand or Demand-Side Management
- ~~Demand that does not adversely impact overall BES reliability where the c~~Circumstances ~~describing~~ where the use of ~~such~~ Demand interruption are documented, including alternatives evaluated; and where the ~~application~~ Demand interruption is subject to review ~~and acceptance~~ in an open and transparent stakeholder process that includes addressing stakeholder comments.

Please Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The SDT is proposing a revision to footnote 'b' in the TPL tables to comply with a FERC directive which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.

   ☐ Yes
   ☐ No
   Comments:

Standards Announcement

Initial Ballot Open December 27, 2010 – January 5, 2011

Now available at: : https://standards.nerc.net/CurrentBallots.aspx

TPL Table 1, Footnote B SAR (Project 2010-11)

An initial ballot is open on Table 1 footnote 'b' in TPL-001-1 through TPL-004-1 until **8 p.m. EDT on January 5, 2011.**

FERC's Order in docket RM06-16-009 requires the ERO to clarify TPL-002-0, Table 1- footnote 'b,' regarding the planned or controlled interruption of electric supply, where a single contingency occurs on a transmission system, and originally directed NERC to file the revised standards by June 30, 2010. To meet this directive, a proposed revision was posted for "Urgent Action" and balloted from May 17-27, 2010. The proposed revision achieved a quorum (84%) and almost enough affirmative votes (64%) to achieve weighted segment approval; however, many balloters provided comments indicating the need for additional modifications. Following the initial ballot, FERC extended the due date to March 31, 2011; thus the project is no longer considered "Urgent Action."

Because Table 1 appears in TPL-001, TPL-002, TPL-003, and TPL-004, the change is reflected in all four standards:

- TPL-001-1 - System Performance Under Normal (No Contingency) Conditions (Category A)
- TPL-002-1b - System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- TPL-003-1a - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
- TPL-004-1 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

Comment Period (through January 5, 2011)

A formal, 45-day comment period began on November 19, 2010 and will conclude when the ballot closes on January 5, 2011. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Next Steps

The drafting team will consider all comments (those submitted with a comment form, and those submitted with a ballot) and will determine whether to make additional changes to the standards. The team will post its response to comments and, if the standards have only minor changes, will post the standards and conduct a 10-day recirculation ballot.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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Standards Announcement

Ballot Pool Open November 19 – December 22, 2010
Comment Period Open November 19 – January 5, 2011

Now available at: http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

TPL Table 1, Footnote B SAR (Project 2010-11)

The TPL Table 1 Order Drafting Team is seeking comments on Table 1 footnote 'b' in TPL-001-1 through TPL-004-1 until **8 p.m. EDT on January 5, 2011.**

FERC's Order in docket RM06-16-009 requires the ERO to clarify TPL-002-0, Table 1- footnote 'b,' regarding the planned or controlled interruption of electric supply, where a single contingency occurs on a transmission system, and originally directed NERC to file the revised standards by June 30, 2010. To meet this directive, a proposed revision was posted for "Urgent Action" and balloted from May 17-27, 2010. The proposed revision achieved a quorum (84%) and almost enough affirmative votes (64%) to achieve weighted segment approval; however, many balloters provided comments indicating the need for additional modifications. Following the initial ballot, FERC extended the due date to March 31, 2011; thus the project is no longer considered "Urgent Action."

Because Table 1 appears in TPL-001, TPL-002, TPL-003, and TPL-004, the change is reflected in all four standards:

- TPL-001-1 - System Performance Under Normal (No Contingency) Conditions (Category A)
- TPL-002-1b - System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- TPL-003-1a - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
- TPL-004-1 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

Ballot Pool (through December 22, 2010)

Because of the length of time between the last ballot (May 2010) and the time of the upcoming ballot (December 2010, many members of the initial ballot pool are no longer in the Registered Ballot Body. The existing ballot pool has been dissolved and a **new ballot pool** is being formed to vote on the proposed revision to Table 1, footnote 'b.' Registered Ballot Body members may join this new ballot pool to be eligible to vote on these proposed modifications **until 8 a.m. EDT on December 22, 2010**.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2010-11_TPL_Table_1_in

Comment Period (through January 5, 2011)
Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Next Steps
An initial ballot will be conducted during the last 10 days of the formal comment period. The drafting team will consider all comments (those submitted with a comment form, and those submitted with a ballot) and will determine whether to make additional changes to the standards. The team will post its response to comments and, if the standards have only minor changes, will post the standards and conduct a 10-day recirculation ballot.

Standards Process
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Standards Announcement

Ballot Pool Open November 19 – December 22, 2010
Comment Period Open November 19 – January 5, 2011

Now available at: http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

TPL Table 1, Footnote B SAR (Project 2010-11)

The TPL Table 1 Order Drafting Team is seeking comments on Table 1 footnote 'b' in TPL-001-1 through TPL-004-1 until **8 p.m. EDT on January 5, 2011.**

FERC's Order in docket RM06-16-009 requires the ERO to clarify TPL-002-0, Table 1- footnote 'b,' regarding the planned or controlled interruption of electric supply, where a single contingency occurs on a transmission system, and originally directed NERC to file the revised standards by June 30, 2010. To meet this directive, a proposed revision was posted for "Urgent Action" and balloted from May 17-27, 2010. The proposed revision achieved a quorum (84%) and almost enough affirmative votes (64%) to achieve weighted segment approval; however, many balloters provided comments indicating the need for additional modifications. Following the initial ballot, FERC extended the due date to March 31, 2011; thus the project is no longer considered "Urgent Action."

Because Table 1 appears in TPL-001, TPL-002, TPL-003, and TPL-004, the change is reflected in all four standards:

- TPL-001-1 - System Performance Under Normal (No Contingency) Conditions (Category A)
- TPL-002-1b - System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- TPL-003-1a - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
- TPL-004-1 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

Ballot Pool (through December 22, 2010)

Because of the length of time between the last ballot (May 2010) and the time of the upcoming ballot (December 2010, many members of the initial ballot pool are no longer in the Registered Ballot Body. The existing ballot pool has been dissolved and a **new ballot pool** is being formed to vote on the proposed revision to Table 1, footnote 'b.' Registered Ballot Body members may join this new ballot pool to be eligible to vote on these proposed modifications **until 8 a.m. EDT on December 22, 2010**.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2010-11_TPL_Table_1_in

Comment Period (through January 5, 2011)

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Next Steps

An initial ballot will be conducted during the last 10 days of the formal comment period. The drafting team will consider all comments (those submitted with a comment form, and those submitted with a ballot) and will determine whether to make additional changes to the standards. The team will post its response to comments and, if the standards have only minor changes, will post the standards and conduct a 10-day recirculation ballot.

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Standards Announcement

Initial Ballot Results

Project 2010-11: TPL Table 1, Footnote B

Now available at: https://standards.nerc.net/Ballots.aspx

An initial ballot of Table 1 footnote 'b' in TPL-001-1 through TPL-004-1 ended on January 5, 2011. Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 90.42%
Approval: 83.33%

Background:
FERC Order RM06-16-009 requires the ERO to clarify TPL-002-0, Table 1 - footnote 'b,' regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system and originally directed NERC to file the revised standards by June 30, 2010. To meet this directive a proposed revision was posted for "Urgent Action" and balloted from May 17-27, 2010. The proposed revision achieved a quorum (84%) and almost enough affirmative votes (64%) to achieve weighted segment approval; however, many balloters provided comments indicating the need for additional modifications. Following the initial ballot, FERC extended the due date to March 31, 2011; thus the project is no longer considered "Urgent Action."

Because Table 1 appears in TPL-001, TPL-002, TPL-003, and TPL-004, the change is reflected in all four standards:

- TPL-001-1 - System Performance Under Normal (No Contingency) Conditions (Category A)
- TPL-002-1b - System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- TPL-003-1a - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
- TPL-004-1 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

More details may be found on the project page:
http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Next Steps
The drafting team will consider all comments (those submitted with a comment form and those submitted with a ballot) and will determine whether to make additional changes to the footnote in the four standards. The team

will post its response to comments and, if the footnote has only minor changes, will post the standards and conduct a 10-day recirculation ballot.

Ballot Criteria

Approval requires both (1) a quorum, which is established by at least 75% of the members of the ballot pool submitting either an affirmative vote, a negative vote, or an abstention, and (2) a two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and non-responses.

Standards Process

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Ballot Results	
Ballot Name:	Project 2010-11 TPL Table 1 Footnote B SAR_in
Ballot Period:	12/27/2010 - 1/5/2011
Ballot Type:	Initial
Total # Votes:	283
Total Ballot Pool:	313
Quorum:	**90.42 % The Quorum has been reached**
Weighted Segment Vote:	83.33 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	95	1	64	0.8	16	0.2	6	9
2 - Segment 2.	11	1	5	0.5	5	0.5	1	0
3 - Segment 3.	66	1	46	0.793	12	0.207	5	3
4 - Segment 4.	26	1	17	0.944	1	0.056	6	2
5 - Segment 5.	58	1	40	0.851	7	0.149	4	7
6 - Segment 6.	37	1	25	0.862	4	0.138	3	5
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.5	5	0.5	0	0	1	2
9 - Segment 9.	4	0.4	4	0.4	0	0	0	0
10 - Segment 10.	8	0.6	6	0.6	0	0	0	2
Totals	**313**	**7.5**	**212**	**6.25**	**45**	**1.25**	**26**	**30**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver		
1	APS	Barbara McMinn	Affirmative	
1	Arizona Public Service Co.	Robert D Smith	Negative	View
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	

1	Avista Corp.	Scott Kinney	Affirmative	View
1	BC Transmission Corporation	Gordon Rawlings	Negative	View
1	Beaches Energy Services	Joseph S. Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	CenterPoint Energy	Paul Rocha	Abstain	
1	Central Maine Power Company	Kevin L Howes	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	View
1	City of Vero Beach	Randall McCamish		
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	View
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker	Affirmative	View
1	Dominion Virginia Power	John K Loftis	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils		
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	GDS Associates, Inc.	Claudiu Cadar	Negative	View
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	View
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stan T. Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Lone Star Transmission, LLC	Julius Horvath	Affirmative	View
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	View
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	National Grid	Saurabh Saksena	Negative	View
1	Nebraska Public Power District	Richard L. Koch	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	View
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David H. Boguslawski	Negative	View
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Douglas G Peterchuck	Affirmative	
1	Oncor Electric Delivery	Michael T. Quinn	Abstain	
1	Orlando Utilities Commission	Brad Chase	Negative	View
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	View
1	PacifiCorp	Colt Norrish	Affirmative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	

1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Linda Brown	Negative	View
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Negative	View
1	Southern Illinois Power Coop.	William G. Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	View
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young	Affirmative	View
1	Tennessee Valley Authority	Larry Akens	Negative	View
1	Tri-State G & T Association, Inc.	Keith V. Carman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Negative	View
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	View
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	Alberta Electric System Operator	Mark B Thompson	Abstain	View
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	View
2	California ISO	Gregory Van Pelt	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Negative	View
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Jason L Marshall	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Negative	View
2	New York Independent System Operator	Gregory Campoli	Affirmative	View
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Negative	View
3	Alabama Power Company	Richard J. Mandes	Negative	View
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Negative	View
3	Arkansas Electric Cooperative Corporation	Philip Huff	Abstain	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	Avista Corp.	Robert Lafferty	Affirmative	View
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	View
3	Black Hills Power	Andy Butcher	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	View
3	City of Leesburg	Phil Janik	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	View
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	Entergy	Joel T Plessinger	Abstain	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Negative	View
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Hydro One Networks, Inc.	David L Kiguel	Affirmative	View
3	JEA	Garry Baker	Affirmative	

3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Negative	View
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Negative	View
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Negative	View
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	PacifiCorp	John Apperson	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	South Carolina Electric & Gas Co.	Hubert C. Young	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	View
3	Tampa Electric Co.	Ronald L Donahey	Affirmative	View
3	Tennessee Valley Authority	Ian S Grant	Negative	View
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power - Ohio	Kevin Koloini	Abstain	
4	American Public Power Association	Allen Mosher	Affirmative	
4	Arkansas Electric Cooperative Corporation	Ronnie Frizzell	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Abstain	
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	LaGen	Richard Comeaux		
4	Modesto Irrigation District	Spencer Tacke	Negative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Oklahoma Municipal Power Authority	Terri Pyle	Abstain	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	View
4	Tallahassee Electric	Allan Morales	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5		Edwin B Cano	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	APS	Mel Jensen	Negative	View
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		

5	Black Hills Corp	George Tatar	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	View
5	City of Tallahassee	Alan Gale	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	View
5	Consumers Energy	James B Lewis	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Electric Power Supply Association	Jack Cashin		
5	Energy Northwest - Columbia Generating Station	Doug Ramey	Affirmative	
5	Entergy Corporation	Stanley M Jaskot		
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	JEA	Donald Gilbert	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	Thomas J Trickey		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	View
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	View
5	New York Power Authority	Gerald Mannarino		
5	Northern California Power Agency	Tracy R Bibb	Abstain	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Pete Ungerman	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	Jerzy A Slusarz	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	View
5	Tenaska, Inc.	Scott M. Helyer	Negative	
5	Tennessee Valley Authority	George T. Ballew	Negative	View
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	View
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Abstain	
5	Xcel Energy, Inc.	Liam Noailles	Abstain	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	View
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	View
6	City of Austin dba Austin Energy	Lisa L Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit		
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View

6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	View
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	View
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Abstain	
8		Roger C Zaklukiewicz		
8		James A Maenner	Affirmative	
8		Edward C Stein	Affirmative	
8	INTELLIBIND	Kevin Conway		
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Transmission Strategies, LLC	Bernie M Pasternack	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	View
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	Oregon Public Utility Commission	Jerome Murray	Affirmative	
9	Snohomish County PUD No. 1	William Moojen	Affirmative	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	View
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B Edge		
10	Southwest Power Pool Regional Entity	Stacy Dochoda		
10	Texas Reliability Entity	Larry D. Grimm	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	View

Individual or group. (27 Responses)
Name (21 Responses)
Organization (21 Responses)
Group Name (6 Responses)
Lead Contact (6 Responses)
Question 1 (27 Responses)
Question 1 Comments (27 Responses)

-
Group
Arizona Public Service Company
Janet Smith
No
It is not clear whether both bullets under "footnote b" have to be met or only one of the two have to be met. It is suggested that the standard be very clear about this.
Group
Northeast Power Coordinating Council
Guy Zito
No
There is concern with the use of the term Demand. It is unclear throughout the footnote whether or not the term Demand includes Interruptible Demand or Demand-Side Management. It is suggested that interruption of Demand be clarified to not include Interruptible Demand or Demand-Side Management to more clearly show the permitted use of Load shedding. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. Language that mitigation of Load and/or Demand interruption should be pursued within the planning process should be reinstated as reinforcement of a Transmission Providers' planning obligations to their load customers, and system operations. Footnote 'b' should be made to read as follows: b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of Load and/or Demand following Contingency events. Interruption of Load and/or Demand is discouraged and all measures to mitigate such interruption should be pursued within the planning process. However, it is recognized that Load and/or Demand will be interrupted if it is directly served by the elements automatically removed from service by the Protection System as a result of a Contingency. Furthermore, in extraordinary circumstances within the planning process Load and/or Demand may need to be interrupted to address BES performance requirements. When interruption of Load and/or Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: • Circumstances where the use of Load and/or Demand interruption are documented, including alternatives evaluated; and where the Load and/or Demand interruption is made available for review in an open and transparent stakeholder process. If Load and/or Demand interruption is necessary, planning should indicate the amount needed, and not specify how it would be obtained. What Load and/or Demand is interrupted is an operational decision. Additional comments not included in the material listed for footnote 'b' on the Comment Form. In the paragraph below the bullets in footnote 'b', confusion is introduced through the use of the term "firm Demand". It is unclear how this is different than the defined term "Firm Demand" and what the implications of the term "firm Demand" are. This footnote should not discourage such adjustments which actually increase the reliability of service to end users. The last sentence of footnote 'b' is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own.
Individual
Aaron Staley
Orlando Utilities Commission
No
The current language provides a balance between the end goal of reliablity (no load loss for B events) and the practical constraint that project cost may outweigh the benefit. Two things are unclear though. Item one: The standard team should clarify if the bullets under note B are intended to be an AND (both conditions met) or an OR (either condition met). As currently written it is not clear. Item #2: The section under firm transfers is in conflict with the section above. If Demand is being curtailed under the first or second bullet and it's served by firm service then service should also be curtailed, however as written any demand served by firm service could not be curtailed.
Individual
Greg Rowland
Duke Energy
Yes
The effective date in the Implementation Plan needs to be changed to match the Effective Date in the standards, in

order to clarify the allowed interruption of Non-consequential load before the new Footnote ‘b’ takes effect.
Individual
Si Truc PHAN
Hydro-Quebec TransÉnergie
Yes
Paragraph should be more clear as: b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances within the planning process, Demand may need to be interrupted to address BES performance requirements. In such case : o Only Interruptible Demand or Demand-Side Management are allowed; o Circumstances where the uses of Demand interruption is needed shall be documented, compared to alternatives, and reviewed in an open and transparent stakeholder process that address stakeholder comments. Curtailment of firm transfers is allowed, when coupled with the appropriate and necessary re-dispatch of resources where it can be demonstrated that this does not result in the shedding of any firm Demand and that Facilities remain within applicable Facility Ratings, including Facilities external to the Transmission Planner’s planning region when they are relied upon.
Group
SERC Planning Standards Subcommittee
Charles W. Long
No
The PSS agrees that the proposed language for footnote b provides some additional clarity. While we generally support the concept, we have concerns that the phrase “is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments” remains ambiguous and should be clarified by limiting stakeholder input to those who have load at risk or local regulators obligated to act on their behalf. Revise the first sentence of the last paragraph to read: “To prepare for a second contingency, curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand.” The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Individual
Tim Ponseti, VP
TVA Trasnmission Plannning & Compliance
No
TVA appreciates the SDT’s efforts to clarify and improve this complex and challenging area. However, as mentioned in our last comments regarding footnote b, TVA still believes that the SDT’s proposal is still focusing more on reliability of local loads than on the overall reliability of the BES. Reliability of local loads should be addressed outside the TPL standards and therefore should not be used/referenced in footnote b. Existing stakeholder processes (referred to in the SDT proposal) typically focus on larger system issues and not on local load serving. TVA believes that some local load should be allowed to be dropped in order to maintain BES reliability. Instead of the proposed footnote b, TVA suggests that the SDT define a “local area” with guidelines detailing the reliability requirements for these local area loads. This would separate the local area load requirements from the BES requirements in the TPL standards.
Individual
Alex Rost
New Brunswick System Operator
No
NBSO agrees with the principles of the current version of the proposed footnote, as far as NBSO’s interpretation of the footnote is correct. NBSO has the following detailed comments: 1. The first paragraph contains many general statements that attempts to capture essential planning principles. NBSO feels that such language is not suited for a footnote. NBSO suggests re-wording of the first paragraph to state: Interruption of Demand may be utilized within the planning process to address BES performance requirements. Such cases are limited to: NBSO also suggests turning the phrase that addresses Demand lost that was served by elements removed from service as a result of a Contingency into a bullet item. NBSO feels that this adds clarity since all of the acceptable instances of Demand interruption are now listed as bulleted items. 2. NBSO interprets that the currently proposed footnote allows for the two bulleted options to be used exclusively or in combination. Thus for clarification NBSO suggests adding “or” after each bulleted item, with the exclusion of the final bulleted item. 3. NBSO suggests removing the last sentence of the last paragraph. Likely all industry members understand that causing reliability concerns in other areas is never acceptable. This principle is not limited to the standard in question, and thus such a statement could require the update of other standards. 4. NBSO interprets that the use of the word “Demand” in the second bullet of the proposed footnote is referring to use of Firm Demand since the first bullet covers the other types of Demand (Demand = Firm Demand + Interruptible Demand). As such NBSO suggests replacing “Demand” with “Firm Demand” in the second bullet. 5. NBSO

feels that the statement “that includes addressing stakeholder comments” should be removed from the last phrase of the second bullet. An open and transparent stakeholder process should adequately address stakeholder comments and concerns. Explicitly specifying that all stakeholder comments be addressed may add undue burden if the word “address” is misconstrued. The task of addressing stakeholder comments is more appropriately addressed and defined in each area’s respective process. 6. NBSO suggests replacing the word “shedding” with “interruption” in the last phrase of the last paragraph to remain consistent with the rest of the proposed footnote. NBSO also suggests capitalizing “firm” in the term “Firm Demand” to remain consistent with the NERC glossary of terms. 7. There is no term “transfers” in the NERC glossary of terms. Perhaps some other defined term from the glossary could be used in lieu of “transfers” (e.g. Firm Transmission Service). Taking into account the NBSO comments, the footnote could read as follows: b) Interruption of Demand may be utilized within the planning process to address BES performance requirements. Such cases are limited to: -Demand directly served by Elements removed from service as a result of a Contingency, or -Use of Interruptible Demand or Demand-Side Management, or -Interruption of Firm Demand when acceptable circumstances for such interruptions are documented (including alternatives evaluated), and where the Firm Demand interruption is subject to review in an open and transparent stakeholder process. Curtailment of Firm Transmission Service is allowed when coupled with the appropriate re-dispatch of resources obligated to do so, and it can be demonstrated that Facilities remain within applicable Facility Ratings and there is no additional interruption of Firm Demand.
Individual
Joe Petaski
Manitoba Hydro
No
The last bullet should be made clearer by adding the words “in jurisdictions” before the word “where”. Not all jurisdictions are mandated to have a stakeholder process, so the standard should be clearly written to recognize this situation. "Circumstances where the use of Demand interruption are documented, including alternatives evaluated; and IN JURISDICTIONS where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments."
Group
PacifiCorp
Sandra Shaffer
Yes
appreciates the efforts of the SDT and supports revision of TLP-002-0 Table 1 footnote “b” as stated in this draft.
Individual
Bernie Pasternack
Transmission Strategies, LLC
Yes
Individual
Michael A. Curtis, General Counsel
Mohave Electric Cooperative
Yes
Group
MRO's NERC Standards Review Subcommittee
Carol Gerou
Yes
Individual
David Thorne
Pepco Holding Inc
Yes
Individual
John Sullivan
Ameren
No
We agree with the statement that an objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following single contingency events. While we appreciate the drafting team’s

efforts in removing the need for acceptance by other parties in the stakeholder process, we still feel that language in the second bullet of the revised footnote b should be modified to remove all references to an open and transparent stakeholder process. Existing RTO stakeholder processes that we are aware of focus on larger system issues, rather than on local load serving issues. Therefore, we believe that the load serving issues following single contingency events are issues between the customer and the utility, and should be addressed in one-on-one forums between those entities.
Individual
Thad Ness
American Electric Power
Yes
Individual
Bob Casey
Georgia Transmission Corporation
Yes
Individual
Alice Ireland
Xcel Energy
No
As this is currently drafted, planners would be required to host a forum with stakeholders to discuss hypothetical actions that may be taken in an emergency. We do not see the value in this, nor is it clear who would be considered stakeholders that should attend this forum. For example, we assume it would be the transmission owner's meeting with distribution providers to discuss the possibility of load shedding. Would that be adequate? Xcel Energy is both a Transmission Planner and a Distribution Provider. In this case would the stakeholder be the end user? This should be struck or more clearly defined.
Individual
Saurabh Saksena
National Grid
No
National Grid supports the direction the drafting team has taken. However, it has a few concerns with the language of the footnote as amended. 1. Use of the term "Demand": In the first sentence, it is unclear whether the term Demand includes Interruptible Demand and Demand-Side Management. It is suggested that interruption of Demand be clarified to exclude Interruptible Demand or Demand-Side Management. 2. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. 3. National Grid also suggests changing "Demand interruption" to "interruption of Demand" in second bullet under "b)" to avoid awkward and incorrect phasing. 4. 'Addressing stakeholder comments' introduces undefined actions which may be required in response to the comments. If 'Demand interruption is subject to review in an open and transparent stakeholder process', then stakeholder comments will be addressed without creating an undefined commitment to require it. As a result, "that includes addressing stakeholder comments" should be deleted. 5. The second paragraph seems to be restricting the use of Demand interruption for the sake of Firm Transfer reduction. This can be stated directly without adding the confusion of re-dispatch. By coupling re-dispatch with a constraint of not shedding Demand, the paragraph also creates confusion as to what to do in a situation where the amount of Demand that is allowed to be shed in the first paragraph could be reduced with re-dispatch. Would re-dispatch not be allowed? National Grid suggests that the paragraph be rewritten as follows: 'Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management).' 6. National Grid seeks clarification if there is an intended distinction between the use of the term "firm Demand" and the defined term "Firm Demand" or is that just a typo? 7. The last sentence of footnote B is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple NERC standards if it were added here, otherwise it would infer that such actions are acceptable in all other standards.
Individual
Andrew Z. Pusztai
American Transmission Company
Yes
Individual
Jason L. Marshall

Midwest ISO
Yes
Group
Southern Company
Andy Tillery
No
Southern Company is voting "no" on the footnote b ballot because of concerns that the reliability of firm transfers could be compromised. The existing Table I Transmission System Standards, which have been in place as early as the 1997 NERC Planning Standards, do not allow Loss of Demand or Curtailed Firm Transfers under single (Category B) contingencies. Footnote B addressed two areas: 1) the loss of radial or local network load, which Southern Company agrees that the drafting team has appropriately clarified and 2) preparing for the next contingency, which Southern Company does not agree has been appropriately clarified. Southern Company believes the proposed wording "Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch" now allows for the curtailment of firm transfers for single contingencies, whereas Southern Company did not believe this was previously permitted under the standards. Southern Company interprets the new language to allow a planner to curtail firm transfers (generation) to address a single contingency. Southern Company interpreted the original language to not permit the curtailment of firm transfers (generation) for a single contingency, but rather that a planner would develop a suitable transmission reinforcement or other mitigation. Southern Company is concerned that the proposed language could result in a degradation in the dependability of firm transfers impacting the reliability of those customers who rely upon them. Southern Company agrees that a system reconfiguration including the redispatch of generation is appropriate when preparing for a second contingency (Category C). Therfore, a distinction is needed between what is allowed in response to a first contingency and what is allowed to be prepared for a second contingency. The curtailment of firm transfers should not be allowed as a response to the first contingency. This practice would undermine the concept of firm transfers. The curtailment of firm transfers should only be allowed in footnote b as a system adjustment to be prepared for a second contingency. We propose the following to clarify that curtailments are permitted only to prepare for the second contingency. "To prepare for the next contingency, curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch".
Individual
Michael Lombardi
Northeast Utilities
No
The revised language of Footnote b suggests that non-consequential demand interruption (load that is not directly served by the elements removed from service as a result of the contingency) could be used to mitigate reliability concerns arising from NERC Category B contingency events (i.e., single element contingencies). This language seems to encourage operational workarounds and adds burdens for operators of the system. NU believes this is not consistent with planning a highly reliable bulk electric system and thus does not support this weaker language.
Individual
Dan Rochester
Independent Electricity System Operator
Yes
Individual
Gregory Campoli
New York Independent System Operator
No
Proposed revised footnote language: b) It is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Interruptible Demand or Demand-Side Management o Circumstances where the uses of firm Demand interruption not directly interrupted by the contingency are documented, including alternatives evaluated; and where the firm Demand interruption is subject to review in an open and transparent stakeholder process. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the interruption of any firm Demand. Comments: There are generic concerns with the footnote as amended that must be addressed. The first is the use of the term “Demand”. It is very unclear throughout the footnote whether or not the term Demand includes Interruptible Demand or Demand-Side Management. It is suggested that interruption of Demand be clarified to not include Interruptible Demand or Demand-Side Management to more clearly show the permitted use of that option for load shedding. Further confusion is introduced through the use of the term “firm Demand” in some locations. It is unclear how this is different

than the defined term “Firm Demand” and what the implications of the term “firm Demand” are. The first and third sentences of the first paragraph are unnecessary and should be deleted. However, if they are to be retained, the first sentence is unacceptable in its current state. In some instances, Interruptible Demand or Demand-Side Management are utilized in lieu of transmission additions. These can be considered as acceptable mitigation and there is no justification to minimize their use. Therefore some clarification to the term Demand in the first sentence must be made. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. The second portion of the second bullet should be deleted as it is unncessary: “and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.” If this is to be retained, the very last portion should be deleted “that includes addressing stakeholder comments”. The term “addressing” is unclear. This can be misconstrued to infer that plans must be changed in response to stakeholder comments. This may be inappropriate and may be impossible if conflicting comments are received. It may also create a new standard that all comments must be “addressed”, which may not be a part of the stakeholder process across NERC’s footprint. The first sentence of the paragraph under the two bullets seems to prevent a situation where a combination of re-dispatch and the interruption of Demand are utilized. This restriction could prevent a situation where the use of re-dispatch decreases the amount of Demand which must be interrupted. This footnote should not discourage such adjustments which actually increase the reliability of service to end users. This same sentence also uses the term “shedding of firm Demand”. This should be replaced with “Demand interruption” such that it is consistent with the second bullet; otherwise an unnecessary new term has been introduced. The last sentence of footnote B is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple NERC standards if it was added here, otherwise it would infer that such actions are acceptable in all other standards.
Individual
Kathleen Goodman
ISO New England Inc
No
The following comments are provided in regard to this proposal. The first and third sentences of the first paragraph are unnecessary. While we agree with the concept, it is unclear as to how inclusion of these sentences in a standard creates a measureable requirement. There are generic concerns with the footnote as currently proposed. The first is the use of the term “Demand.” It is unclear whether the term Demand includes Interruptible Demand and Demand-Side Management. It is suggested that interruption of Demand be clarified to exclude Interruptible Demand and Demand-Side Management to more clearly show the permitted use of those options. The second concern is that it is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. The third is that not all areas have stakeholder processes. Documenting the use of Demand Interruption should be sufficient without requiring stakeholder review. Therefore the second portion of the second bullet “including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments” is unnecessary and should be deleted. “Addressing stakeholder comments” introduces undefined actions which may be required in response to the comments. For those areas that already have stakeholder processes, stakeholder comments are by definition addressed. As a result, at a minimum “that includes addressing stakeholder comments” should be deleted. Furthermore, for areas that do not have stakeholder processes, so long as they publish their studies impacted parties are aware of the role of demand response. The fourth is that the second paragraph seems to be restricting the use of Demand interruption for the sake of Firm Transfer reduction. This can be stated directly without adding the confusion of re-dispatch. By coupling re-dispatch with a constraint of not shedding Demand, the paragraph also creates confusion as to what to do in a situation where the amount of Demand that is allowed to be shed in the first paragraph could be reduced with re-dispatch. Would re-dispatch not be allowed? We suggest that the paragraph be rewritten as follows: “Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management).” The fifth is if the term ‘firm demand’ survives the proposed changes; is there an intended distinction between the use of the term “firm Demand” and the defined term “Firm Demand”? If these terms are intended to be differently, it is unclear what the term “firm Demand” represents. The final comment is that the last sentence of footnote B is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple NERC standards if it was added here, otherwise it would infer that such actions are acceptable in all other standards. If the first and third sentences must be retained the following wording for the footnote is proposed: b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand, (excluding Interruptible Demand or Demand-Side Management), following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Interruptible Demand or Demand-Side Management o Circumstances where the uses of Demand interruption not directly interrupted by the contingency are documented. Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than

Interruptible Demand or Demand Side Management).
Individual
Harold Wyble
Kansas City Power & Light
Yes

Consideration of Comments on Successive Ballot — Project 2010-11 – TPL Table 1, Footnote b

Successive Ballot Dates: **12/27/2010 - 1/5/2011**

Summary Consideration:

The SDT reviewed all of the comments received and has made a clarifying change to the structure of the footnote to address industry concerns as to the intent of the SDT. No contextual changes have been made to the footnote. Therefore, the SDT is recommending that this project be moved to a recirculation ballot.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

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

Balloter	Company	Seg-ment	Vote	Comment
Richard J. Mandes	Alabama Power Company	3	Negative	Southern Company is voting "no" on the footnote b ballot because of concerns that the reliability of firm transfers could be compromised. The existing Table I Transmission System Standards,

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Balloter	Company	Seg-ment	Vote	Comment
Anthony L Wilson	Georgia Power Company	3	Negative	which have been in place as early as the 1997 NERC Planning Standards, do not allow Loss of Demand or Curtailed Firm Transfers under single (Category B) contingencies. Footnote B addressed two areas: 1) the loss of radial or local network load, which Southern Company agrees that the drafting team has appropriately clarified and 2) preparing for the next contingency, which Southern Company does not agree has been appropriately clarified. Southern Company believes the proposed wording "Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch" now allows for the curtailment of firm transfers for single contingencies, whereas Southern Company did not believe this was previously permitted under the standards. Southern Company interprets the new language to allow a planner to curtail firm transfers (generation) to address a single contingency. Southern Company interpreted the original language to not permit the curtailment of firm transfers (generation) for a single contingency, but rather that a planner would develop a suitable transmission reinforcement or other mitigation. Southern Company is concerned that the proposed language could result in a degradation in the dependability of firm transfers impacting the reliability of those customers who rely upon them. Southern Company agrees that a system reconfiguration including the redispatch of generation is appropriate when preparing for a second contingency (Category C). Therfore, a distinction is needed between what is allowed in response to a first contingency and what is allowed to be prepared for a second contingency. The curtailment of firm transfers should not be allowed as a response to the first contingency. This practice would undermine the concept of firm transfers. The curtailment of firm transfers should only be allowed in footnote b as a system adjustment to be prepared for a second contingency. We propose the following to clarify that curtailments are permitted only to prepare for the second contingency. "To prepare for the next contingency, curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch".
Don Horsley	Mississippi Power	3	Negative	
Horace Stephen Williamson	Southern Company Services, Inc.	1	Negative	

Response: The SDT has changed the wording 'coupled with' to 'achieved through' to better clarify the SDT's intent.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~-C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand

Balloter	Company	Seg-ment	Vote	Comment
interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~ As drafted, footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. It further clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the footnote. No change made.				
Jennifer Richardson	Ameren Energy Marketing Co.	6	Negative	We agree with the statement that an objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following single contingency events. While we appreciate the drafting team's efforts in removing the need for acceptance by other parties in the stakeholder process, we still feel that language in the second bullet of the revised footnote b should be modified to remove all references to an open and transparent stakeholder process. Existing RTO stakeholder processes that we are aware of focus on larger system issues, rather than on local load serving issues. Therefore, we believe that the load serving issues following single contingency events are issues between the customer and the utility, and should be addressed in one-on-one forums between those entities.
Kirit S. Shah	Ameren Services	1	Negative	
Response: The SDT disagrees that this should be handled through two party interactions. The SDT believes that in situations where an entity's planning studies require the interruption of Firm Demand to remain within BES Facility Ratings that the entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be impacted by those decisions have the ability to review those plans**.** No change made.				
Steven Norris	APS	3	Negative	It is not clear whether both bullets under "footnote b" have to be met or only one of the two have to be met. It is suggested that the standard be very clear about this
Mel Jensen	APS	5	Negative	
Robert D Smith	Arizona Public Service Co.	1	Negative	
Response: The bullets – o Interruptible Demand or Demand-Side Management and o Circumstances where … are not requirements that must be met, but rather they define the conditions, either one or both, where Load is allowed to be interrupted. The SDT has rearranged the footnote to clarify the intent of the footnote. **b)** An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch,				

Balloter	Company	Seg-ment	Vote	Comment
				where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~ ~~-C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~
John Tolo	Tucson Electric Power Co.	1	Negative	The first sentence of the second paragraph appears to conflict with the first paragraph in that it indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.
Scott Kinney	Avista Corp.	1	Affirmative	The first sentence of the second paragraph appears to conflict with the first paragraph in that it indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.
Robert Lafferty	Avista Corp.	3	Affirmative	
Brenda S. Anderson	Bonneville Power Administration	6	Affirmative	Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.
William Mitchell Chamberlain	California Energy Commission	9	Affirmative	I am voting for this improved standard but I am concerned that the first sentence of the second paragraph appears to conflict with the first paragraph in that it indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. This problem could be corrected by adding language to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.

Balloter	Company	Seg-ment	Vote	Comment
Chang G Choi	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	1	Affirmative	Tacoma Power agrees that the revision is better than the existing language. However, to improve clarity on the interrelationship of the 2 paragraphs of Footnote B, we strongly suggest adding the following phrase to the end of the first sentence of the second paragraph, "unless the firm Demand is allowed to be shed pursuant to the above paragraph in this footnote."
Max Emrick	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	5	Affirmative	
James Tucker	Deseret Power	1	Affirmative	As drafted the first paragraph of proposed Footnote B identifies the objective of minimizing interruption of Demand following Contingencies and goes on to identify the limited situation where interruption of demand may be necessary. However, the first sentence of the second paragraph appears to conflict with the first paragraph in that it indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed
Chifong L. Thomas	Pacific Gas and Electric Company	1	Affirmative	PG&E supports the proposed footnote B. We believe, however, there is a potential for confusion with the language as currently drafted. As drafted the first paragraph of proposed Footnote B identifies the limited situations where interruption of demand may be necessary and would be allowed. However, the first sentence of the second paragraph indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. Taken together with the first paragraph, this requirement can be confusing because the first paragraph potentially conflicts with the second paragraph. Please change the first sentence in the second paragraph to read, "Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand, the interruption of which is otherwise allowed as described above."
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Affirmative	Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.
Travis Metcalfe	Tacoma Public Utilities	3	Affirmative	Tacoma Power agrees that the revision is better than the existing language. However, to improve clarity on the interrelationship of the 2 paragraphs of Footnote B, we strongly suggest adding the following phrase to the end of the first sentence of the second paragraph, "unless the firm Demand is allowed to be shed pursuant to the above paragraph in this footnote."

Balloter	Company	Seg-ment	Vote	Comment
Keith Morisette	Tacoma Public Utilities	4	Affirmative	
Michael C Hill	Tacoma Public Utilities	6	Affirmative	
Beth Young	Tampa Electric Co.	1	Affirmative	Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed
Ronald L Donahey	Tampa Electric Co.	3	Affirmative	
RJames Rocha	Tampa Electric Co.	5	Affirmative	Recommend adding language to paragraph 2, sentence 1 to clarify shedding of firm demand is allowed as stated in Paragraph 1.
Benjamin F Smith II	Tampa Electric Co.	6	Affirmative	
Melissa Kurtz	U.S. Army Corps of Engineers	5	Affirmative	Language needs to be added to the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.
Brandy A Dunn	Western Area Power Administration	1	Affirmative	As drafted, the first paragraph of proposed Footnote B identifies the objective of minimizing interruption of Demand following Contingencies and goes on to identify the limited situation where interruption of demand may be necessary. However, the first sentence of the second paragraph appears to conflict with the first paragraph in that it indicates that curtailment of transfers is allowed under certain conditions as long as it doesn't result in the shedding of any firm Demand. Western recommends that the Drafting Team include language at the end of the first sentence of the second paragraph of Footnote B that clarifies that the shedding of firm Demand as clarified in paragraph one of Footnote B is allowed.

Balloter	Company	Seg-ment	Vote	Comment
Louise McCarren	Western Electricity Coordinating Council	10	Affirmative	WECC supports the concept that is clarified in the proposed language for Footnote B. We have noted however, what could potentially be confusing language between paragraphs one and two of the proposed language. Paragraph one correctly indicates that one of the objectives of transmission planning is to minimize the likelihood and magnitude of interruption of Demand. The first paragraph also recognizes that while this is an objective, there may be certain limited conditions where Demand is interrupted. In recognizing this, the first paragraph lists those limited instances when Demand may be interrupted. However, the first sentence of paragraph two could be interpreted to mean that shedding of Firm Demand is not allowed. The sentence means that shedding of Firm Demand is not allowed due to curtailment of firm transfers, but if there is a situation where curtailment of firm transfers is necessary and curtailment of Demand per the reasons listed in the first paragraph occurs, it should be clear that this is allowed. Suggest adding the following language, or something similar, to the end of the first sentence of the second paragraph of Footnote B. ...except as allowed above.

Response: The SDT has reorganized the footnote to clarify intent and address the issue raised.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

Balloter	Company	Seg-ment	Vote	Comment
Venkataramakrishnan Vinnakota	BC Hydro	2	Negative	Footnote "b" of TPL-001/2/3/4 is still vague and not acceptable. The last paragraph of Footnote b now reads: "Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected." We would like the SDT to answer the following questions related to the paragraph quoted above: 1) What is meant by "firm transfers"? Is it simply energy flowing in real-time on Firm Transmission Service (NERC defined term) that was not previously curtailed in the hour-ahead or day-ahead scheduling processes, or does it refer to ALL Firm Transmission Service that was sold on a path? 2) Please provide an example of what an "appropriate re-dispatch of resources obligated to re-dispatch" could look like? 3) Assuming an outage of a single transmission line (N-1 Category B event) has occurred and assuming that no "resources [are] obligated to redispatch" for this outage, would a transmission provider be allowed to curtail Firm Transmission Service that it has sold in order to prepare to withstand the next worst credible contingency? 4) Would transmission providers be allowed to sell Firm Transmission Service on a path above what could be delivered with any one element of that path out of service across a range of operating conditions? 5) If the proposed Footnote b is approved, and assuming an appropriate obligation to redispatch could not be negotiated, would utilities have to reinforce their system (within 60 months) to ensure that Firm Transmission Services already sold on particular paths would not be curtailed when any one element of that path is out of service? 6) If a transmission provider employs Generation Dropping for single contingencies in order to support Firm Transmission Service between regions, and assuming there are no provisions for obligated re-dispatch, would the proposed Footnote b force a recalculation of firm vs non-firm transfer capability? 7) Path 66 (PACI) and Path 65 (PDCI) can both see significant derates in their firm transfer capability for single contingencies. How would the proposed Footnote b impact Firm Transmission on these paths? Further, the Project 2010-11 SDT (Footnote "b") should be amalgamated with the Project No. 2006-02 SDT (TPL-001 through TPL004 amalgamation/update): 1. It doesn't make any sense to update Footnote "b" of TPL-001 based on the existing approved

Balloter	Company	Seg-ment	Vote	Comment
				version of TPL-001 when the language in that standard is being revised and terms that Footnote "b" makes reference to will be changed. Draft #6 (2010-Oct-19) of TPL-001 has changed "Footnote b" to "Footnote 9". 2. Draft #6 of TPL-001 has changed the column heading relevant to "Footnote b" from "Loss of Demand or Curtailed Firm Transfers" to "Interruption of Firm Transmission Service Allowed". 3. Draft #6 of TPL-001 has seven new definitions including the following two definitions that would be expected to be relevant to Footnote b: 3.1. Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault. 3.2. Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment. 4. The Project 2006-02 SDT has placed Draft #6 of TPL-001 on hold, stating, "The team will delay moving the standard forward until the resolution of "footnote b" has become clear."
Response: 1. For consistency with the existing standard text, the term 'firm transfer' is retained. Therefore, the interpretation of "firm transfers" remains unchanged. 2. One example would be a contractual arrangement that defines clear expectations to alternately serve Load upon the removal of the firm transfer so that no loss of Load occurs. 3. In the planning timeframe, footnote 'b' addresses single Contingencies (Cat. B) and footnote 'c' addresses the Cat. C Contingencies. Neither footnote prohibits System adjustments, which could include re-dispatch of your own resources to prepare for the next Contingency. 4. How Firm Transmission Service (FTS) is sold is addressed in individual tariffs in concert with the MOD standards. 5. The implementation plan provides 60 months after regulatory approval for entities to comply with the modified standard. How that is accomplished is up to individual entities. 6. & 7 Each circumstance may need to be evaluated individually and additional documentation of understandings may be necessary. 7-1 - 4. Based on ballot comments and regulatory orders, the SDT determined that the best course of action was to address footnote 'b' as a standalone item and then incorporate the changes approved for footnote 'b' into the new TPL-001-2 in a manner consistent with the other proposed changes in TPL-001-2.				
Christopher L de Graffenried	Consolidated Edison Co. of New York	1	Negative	Interruptible Demand, like Demand-Side-Management, is an operational tool. We do not believe it appropriate to use operational tools for transmission planning. A load serving entity should not claim to serve loads it plans to disconnect during a design contingency. In other words, these loads should be excluded from the load forecast in the first place and, thereby, would not be represented in power flows that are utilized to assess system performance under the TPL standards. This approach prevents the use of such load interruptions to address any deficiency found in TPL-type
Peter T Yost	Consolidated Edison Co. of New York	3	Negative	

Balloter	Company	Seg-ment	Vote	Comment
Wilket (Jack) Ng	Consolidated Edison Co. of New York	5	Negative	assessments.
Nickesha P Carrol	Consolidated Edison Co. of New York	6	Negative	
Response: Entities across the continent have many different Interruptible and Demand-Side Management programs that have many different attributes and rules. Some entities have Interruptible Demand programs that are appropriate for planning purposes.				
Chuck B Manning	Electric Reliability Council of Texas, Inc.	2	Negative	The introductory paragraph of footnote b includes policy language. Since this is a reliability standard-and not a policy directive-the general narrative setting forth the desired policy goal of minimizing load-shedding is misplaced. Including policy language can cloud the specific issues the standard attempts to address, and ERCOT recommends deleting the first two sentences in the introductory paragraph. The next sentence in the introductory paragraph goes on to state, generally, that demand may be interrupted to "address BES performance requirements.” This phrase is vague. To which performance requirements does this refer? The intent is not clear. If the intent is to generally recognize the need to shed load to respect to NERC standards and to allow flexibility for an entity to exercise discretion relative to meeting BES performance requirements, then that intent should be clearly reflected in the language. Furthermore, the last sentence of the introductory paragraph and the subsequent bullet points are arguably inconsistent with this approach, because they could be viewed as removing an entity’s flexibility/discretion by limiting the circumstances when load can be shed. The second bullet point is unnecessary, because it is already apparent that interruptible demand/demand side management programs can be used according to their terms. This could create confusion in that it could be implied that, absent the need to use these to meet BES performance requirements, using them otherwise is inconsistent with/not allowed under footnote b. Simply put, those products are not load shedding as contemplated by this footnote. Therefore they should not be listed here. With respect to the third bullet point, the phrase "demand that does not adversely impact overall BES reliability" is not adequately defined, and provides opportunity for confusion. This is an ambiguous phrase and can’t be linked back to objective NERC standards/requirements. The bullet points should avoid ambiguity to mitigate ambiguity risk in audits.

Balloter	Company	Seg-ment	Vote	Comment
				In addition, the last part of the language in this bullet imposing an open and transparent stakeholder process is unclear. What is the intent behind requiring review in a stakeholder process? If it is to establish the ability of the entity to develop load shedding procedures beyond those explicitly contemplated in footnote b, ERCOT questions if it is reasonable for the responsible entity to be required to get "permission" from stakeholders to implement reliability measures related to its obligation as the functional entity. Again, the language simply is not clear. Accordingly, ERCOT recommends this bullet point be removed. If it is retained, it should be revised consistent with these comments to remove ambiguous language to mitigate potential confusion around the meaning/scope of the footnote in the administration of the CMEP. In addition, ERCOT recommends revising the draft footnote b to allow for planned Demand interruption as a means of mitigation during interim periods when a unanticipated (such as unexpected demand growth or unit retirements) or temporary change on the system occurs in a timeframe that is shorter than the time necessary to plan and implement the system upgrades necessary to avoid the Demand interruption. Finally, in the last paragraph of footnote b, it isn't clear why "Transmission Service" was changed to "transfers." Firm transmission service is a service provided in some regions, and it provides relative value to other types of services-e.g., non-firm and network. The mention of transmission service may also be irrelevant in this footnote, since the allowance of its interruption doesn't also allow for load shedding. Therefore, ERCOT recommends eliminating the last paragraph of footnote b.

Response: The SDT believes that the first part of the footnote is necessary to provide context for the items that follow and has crafted the language to provide a balance between flexibility and consistency across NERC. No change made.

The term "BES performance requirements" references the other requirements within the TPL standard and the SDT has removed the phrase "demand that does not adversely impact overall BES reliability".

In a previous posting, entities had stated that it was not clear that the use of Interruptible Load and Demand Side Management was permitted. The SDT added this section to address those concerns. The SDT has reorganized and reformatted the footnote to improve clarity.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm

Balloter	Company	Seg-ment	Vote	Comment
Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~ The open and transparent process does not require "permission", but rather it facilitates the open sharing of information between entities that have responsibility for ensuring BES reliability. The SDT decided to not limit the use of the footnote to a specific time period because there are circumstances where the longer term use may be implemented without adversely impacting BES reliability. For consistency with the existing standard text, the term 'firm transfer' is retained. No change made.				
Claudiu Cadar	GDS Associates, Inc.	1	Negative	We appreciate all the work conducted by SDT to adjust current footnote "b" however, we disagree with the current approach mainly from the same reasons iterated during last comment period, as follows: • The definition does not go far enough with recognition that interruption of Demand should be mitigated if at all possible. The language should encourage the TP to develop mitigation plans that could be implemented as an alternative to Demand interruption. • Use of Interruptible Demand should only be implemented if the Transmission Planner can point to a contract between the Transmission Provider and Transmission Customer that permits load curtailment. • Under FERC Order 890, Conditional Firm transmission service can be granted for entities who voluntarily acknowledge the right of the Transmission Provider to curtail their transaction or provide re-dispatch. This should be the only transfer which can be utilized in the Planning Horizon for interruption of Demand for Note b. We suggest using the following wording as emphasized below: "An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events and to develop mitigation plans that do not call for the curtailment of Demand.

Balloter	Company	Seg-ment	Vote	Comment
				It is recognized that Demand will be interrupted if it is directly served by the elements removed from service as a result of the Contingency and in very limited circumstances when approaching intermediate solutions to restore BES reliability. When interruption of Demand is utilized within the planning process, such interruption is limited to: ? Demand that is directly served by the elements that are removed from service as a result of the Contingency, ? Interruptible Demand or Demand-Side Management, where the Customer has given explicit rights to the Transmission Provider for curtailment of their Demand, ? Demand, other than Interruptible Demand or Demand-Side Management, that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand are documented, including alternatives evaluated; where the Load-Serving Entity who has responsibility for serving such Demand has agreed to the curtailment, and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of Firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch per the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected. In addition, any Conditional Firm transfers may be curtailed, in accordance with the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider."
Response: In the footnote, the SDT has acknowledged that interrupting Firm Demand is not the preferred solution to BES concerns, while recognizing that this may not always be possible. The SDT believes that the footnote as drafted strikes an appropriate balance. No change made. It is well understood that there must be some agreement or contract before interruptible Demand or Demand-Side Management can be utilized by the planner. The SDT disagrees that there should be a prohibition on utilizing other resources obligated to re-dispatch for Contingencies, unless it has been characterized as "conditional firm". Entities should not be restricted from utilizing other dispatch scenarios, as long as Firm Demand is not interrupted. For the reasons stated above, the SDT has not modified the footnote as suggested.				
Joe D Petaski	Manitoba Hydro	1	Negative	The last bullet should be made clearer by adding the words "in jurisdictions" before the word "where". Not all jurisdictions are mandated to have a stakeholder process, so the standard should be clearly written to recognize this situation. "Circumstances where the use of Demand interruption are documented, including alternatives evaluated; and IN JURISDICTIONS where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments."
Greg C. Parent	Manitoba Hydro	3	Negative	
S N Fernando	Manitoba Hydro	5	Negative	
Daniel	Manitoba Hydro	6	Negative	

Balloter	Company	Seg-ment	Vote	Comment
Prowse				
Response: The SDT believes that if Firm Demand is planned to be interrupted utilizing footnote 'b', there must be an open and transparent stakeholder process to ensure that all parties that may be impacted have been notified and have an opportunity to provide comments. No change made.				
Spencer Tacke	Modesto Irrigation District	4	Negative	I am voting NO on the proposed revision because the second bullet of the proposed revision is nebulous as to how the exemption process will occur, and how it will be monitored by the auditors. Also, the last sentence of the last paragraph of the proposed change is nebulous about keeping facility flows within applicable Normal and Emergency thermal ratings. Thank you.
Response: Rather than mandate a one-size-fits-all process, the SDT has provided entities the latitude to utilize existing processes, modify existing processes, or create new processes to provide an open and transparent stakeholder process. The SDT cannot comment on future actions of the auditors. The SDT disagrees that maintaining Facilities within applicable Facility Ratings is a nebulous concept. That part of the footnote was included to ensure that the plans to resolve a situation on a planner's System did not create other overloads. No change made.				
Saurabh Saksena	National Grid	1	Negative	National Grid supports the direction the drafting team has taken. However, it has a few concerns with the language of the footnote as amended. 1. Use of the term "Demand": In the first sentence, it is unclear whether the term Demand includes Interruptible Demand and Demand-Side Management. It is suggested that interruption of Demand be clarified to exclude Interruptible Demand or Demand-Side Management. 2. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet.

Balloter	Company	Seg-ment	Vote	Comment
Michael Schiavone	Niagara Mohawk (National Grid Company)	3	Negative	3. National Grid also suggests changing "Demand interruption" to "interruption of Demand" in second bullet under "b)" to avoid awkward and incorrect phasing. 4. 'Addressing stakeholder comments' introduces undefined actions which may be required in response to the comments. If 'Demand interruption is subject to review in an open and transparent stakeholder process', then stakeholder comments will be addressed without creating an undefined commitment to require it. As a result, "that includes addressing stakeholder comments" should be deleted. 5. The second paragraph seems to be restricting the use of Demand interruption for the sake of Firm Transfer reduction. This can be stated directly without adding the confusion of re-dispatch. By coupling re-dispatch with a constraint of not shedding Demand, the paragraph also creates confusion as to what to do in a situation where the amount of Demand that is allowed to be shed in the first paragraph could be reduced with re-dispatch. Would re-dispatch not be allowed? National Grid suggests that the paragraph be rewritten as follows: 'Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management).' 6. National Grid seeks clarification if there is an intended distinction between the use of the term "firm Demand" and the defined term "Firm Demand" or is that just a typo? 7. The last sentence of footnote B is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple NERC standards if it were added here, otherwise it would infer that such actions are acceptable in all other standards.

Response: 1. The SDT has reorganized the text in the footnote to address this concern.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

Balloter	Company	Seg-ment	Vote	Comment
~~Interruptible Demand or Demand Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~ **2.** The SDT has reorganized the text in the footnote to address this concern. **3.** The SDT believes that the proposed change does not add additional clarity to the footnote. No change made. **4.** The SDT disagrees that each review process automatically will have a response to comments element. Therefore, the SDT added that element to ensure that all stakeholder processes will include that element. No change made. **5.** The SDT has reorganized the text in the footnote to address this concern. **6.** The SDT has corrected the capitalization errors. **7.** Since the planned action of curtailing of firm transfers may adversely impact neighboring systems, the SDT believes that it is important in this situation to articulate a condition that is normally implied. The SDT disagrees that an explicit statement in this footnote changes the intent of all other standards. No change made.				
Tony Eddleman	Nebraska Public Power District	3	Negative	NPPD votes NO due to the ambiguity of the terms "Curtailment of firm transfers is allowed, when coupled the appropriate re-dispatch of resources" with respect to a Category B contingency event. NPPD does not support the curtailment of firm transfers or re-dispatch to meet the performance requirements during a Category B (N-1) event. Curtailment of firm transfers and re-dispatch are allowable following acceptable performance for the Category B (N-1) event, to get ready for the next Category C type of event.
Don Schmit	Nebraska Public Power District	5	Negative	
Response: As drafted, footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. It further clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. No change made.				

Balloter	Company	Seg-ment	Vote	Comment
Randy MacDonald	New Brunswick Power Transmission Corporation	1	Negative	In general: NERC standards should not dictate circumstances or acceptable transmission contingencies under which the tripping of customers loads is acceptable. That should be an issue between the utility of supply, the customer, and the local regulating body so long as the interruption to customers (for whatever contingency) is controlled and does not cause problems on the BES, or to neighboring utilities. Specifically, 1. The second bullet: The last sentence (following the semicolon) should be removed. The local regulating body should provide input or approval. 2. NB Power Transmission interprets that the currently proposed footnote allows for the two bulleted options to be used exclusively or in combination. Thus for clarification suggest adding "or" after the first bulleted item.

Response: The SDT disagrees that this should be handled exclusively with the local regulating body. The SDT believes that in situations where an entity's planning studies require the interruption of Firm Demand to remain within BES Facility Ratings that the entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be adversely impacted by those decisions have the ability to review those plans**.** No change made.

The SDT has reorganized the footnote to clarify its intent and address the issue raised.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~-C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

Balloter	Company	Seg-ment	Vote	Comment
Alden Briggs	New Brunswick System Operator	2	Negative	NBSO agrees with the principles of the current version of the proposed footnote assuming NBSO's interpretation of the footnote is correct. NBSO has the following detailed comments: 1. The first paragraph contains many general statements that attempts to capture essential planning principles. NBSO feels that such language is not suited for a footnote. NBSO suggests re-wording of the first paragraph to state: Interruption of Demand may be utilized within the planning process to address BES performance requirements. Such cases are limited to: NBSO also suggests turning the phrase that addresses Demand lost that was served by elements removed from service as a result of a Contingency into a bullet item. NBSO feels that this adds clarity since all of the acceptable instances of Demand interruption are now listed as bulleted items. 2. NBSO interprets that the currently proposed footnote allows for the two bulleted options to be used exclusively or in combination. Thus for clarification NBSO suggests adding "or" after each bulleted item, with the exclusion of the final bulleted item. 3. NBSO suggests removing the last sentence of the last paragraph. Likely all industry members understand that causing reliability concerns in other areas is never acceptable. This principle is not limited to the standard in question, and thus such a statement could require the update of other standards. 4. NBSO interprets that the use of the word "Demand" in the second bullet of the proposed footnote is referring to use of Firm Demand since the first bullet covers the other types of Demand (Demand = Firm Demand + Interruptible Demand). As such NBSO suggests replacing "Demand" with "Firm Demand" in the second bullet. 5. NBSO feels that the statement "that includes addressing stakeholder comments" should be removed from the last phrase of the second bullet. An open and transparent stakeholder process should adequately address stakeholder comments and concerns. Explicitly specifying that all stakeholder comments be addressed may add undue burden if the word "address" is misconstrued. The task of addressing stakeholder comments is more appropriately addressed and defined in each area's respective process. 6. NBSO suggests replacing the word "shedding" with "interruption" in the last phrase of the last paragraph to remain consistent with the rest of the proposed footnote. NBSO also suggests capitalizing "firm" in the term "Firm Demand" to remain consistent with the NERC glossary of terms.

Balloter	Company	Seg-ment	Vote	Comment
				7. There is no term "transfers" in the NERC glossary of terms. Perhaps some other defined term from the glossary could be used in lieu of "transfers" (e.g. Firm Transmission Service). Taking into account the NBSO comments, the footnote could read as follows: b) Interruption of Demand may be utilized within the planning process to address BES performance requirements. Such cases are limited to: -Demand directly served by Elements removed from service as a result of a Contingency, or -Use of Interruptible Demand or Demand-Side Management, or -Interruption of Firm Demand when acceptable circumstances for such interruptions are documented (including alternatives evaluated), and where the Firm Demand interruption is subject to review in an open and transparent stakeholder process. Curtailment of Firm Transmission Service is allowed when coupled with the appropriate re-dispatch of resources obligated to do so, and it can be demonstrated that Facilities remain within applicable Facility Ratings and there is no additional interruption of Firm Demand.

Response: 1 & 2. The SDT believes that the first part of the footnote is necessary to provide context for the items that follow and has crafted the language to provide a balance between flexibility and consistency across NERC. The SDT has reorganized the footnote to clarify its intent and address the issue raised.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~-C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

3. Since the planned action of curtailing of firm transfers may adversely impact neighboring Systems, the SDT believes that it is important in this situation to articulate a condition that is normally implied. The SDT disagrees that an explicit statement in this footnote changes the intent of all other standards.
4. The SDT has reorganized the footnote to clarify its intent and address the issue raised.
5. The SDT believes that in situations where an entity's planning studies require the interruption of Firm Demand to remain within BES Facility Ratings that the

Balloter	Company	Seg-ment	Vote	Comment
entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be adversely impacted by those decisions have the ability to review those plans. No change made. **6.** The SDT does not believe that replacing the term shedding with interruption adds clarity and did not make the proposed change. The SDT has reorganized the footnote to clarify its intent and address the second issue. **7.** For consistency with the existing standard text, the term 'firm transfer' is retained. No change made.				
David H. Boguslawski	Northeast Utilities	1	Negative	The revised language of Footnote b suggests that non-consequential demand interruption (load that is not directly served by the elements removed from service as a result of the contingency) could be used to mitigate reliability concerns arising from NERC Category B contingency events (i.e., single element contingencies). This language seems to encourage operational workarounds and adds burdens for operators of the system. NU believes this is not consistent with planning a highly reliable bulk electric system and thus does not support this weaker language.
Response: The SDT believes that the language in this footnote is not weaker and does not encourage operational workarounds. The footnote language provides the framework necessary to ensure that in situations where an entity's planning studies require the interruption of Firm Demand to remain within BES Facility Ratings that the entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be adversely impacted by those decisions have the ability to review those plans. No change made.				
Brad Chase	Orlando Utilities Commission	1	Negative	"Two Items prevent us from voting yes. Item #1: The standard team should clarify if the bullets under note B are intended to be an AND (both conditions met) or an OR (either condition met). As currently written it is not clear. Item #2: The section under firm transfers is in conflict with the section above. If Demand is being curtailed under the first or second bullet and it's served by firm service then service should also be curtailed, however as written any demand served by firm service could not be curtailed. Other then these items the revisions does an excellent job of addressing the issue of load shedding under first contingency conditions and practical reliablity."
Ballard Keith Mutters	Orlando Utilities Commission	3	Negative	
Response: The SDT has reorganized the footnote to clarify its intent and address this issue. b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~				

Balloter	Company	Seg-ment	Vote	Comment
				~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~
Linda Brown	San Diego Gas & Electric	1	Negative	Footnote b is a group of exceptions to the requirements for Category B contingencies. To add clarity to the footnote, SDG&E would prefer that each exception be listed separately within the footnote. As SDG&E understands the footnote, the following exceptions can occur after the loss of a single element, • Interruptible Demand can be used to unload a circuit, but the circuit(s) must remain below emergency rating(s) at all times. • Demand-Side Management can be used to unload a circuit, but the circuit(s) must remain below emergency rating(s) at all times. • Demand served by a radial element which is faulted may be interrupted. • Curtailment of firm transfers is allowed, when coupled with re-dispatch of resources obligated to re-dispatch. SDG&E votes against the proposed language for the following reasons: SDG&E feels system reliability alone should drive the need for a technical standard and the language of the standard should reflect the need without reference to the process. FERC Order 890 set the forum for the stakeholder process which provides commercial incentives and a level playing field for any participant to build a transmission project. When considering compliance to the standards, reference to "stakeholder process" is inappropriate and should be removed. Section 4 of the TPL standards assigns responsibility for meeting the standards to the Planning Authority and the Transmission Planner. These entities are subject to penalties if the requirement is not met. Use of "stakeholder process" in the requirement implies that entities other than the Planning Authority or the Transmission Planner have authority over how the standards are to be met without any financial risk. If the "stakeholder process" language is not removed, SDG&E feels stakeholders involved in the process should be registered with NERC and subject to the same audit requirements and penalties as the Planning Authority or the Transmission Planner. Furthermore, the California Transmission Owners have a FERC approved stakeholder process that is administered by the California ISO. Addition of the term "stakeholder process" in a standard may have unintended consequences.

Balloter	Company	Seg-ment	Vote	Comment
Response: While the SDT believes that SDG&E proposed bullet list is consistent with the footnote as drafted, the list is not as inclusive as the footnote. Therefore, the SDT has retained the existing text and reorganized the footnote for clarity. b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~ The SDT believes that in situations where an entity's planning studies require the interruption of Firm Demand to remain within BES Facility Ratings that the entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be adversely impacted by those decisions have the ability to review those plans. No change made.				
Charles H Yeung	Southwest Power Pool	2	Negative	The second paragraph of the footnote seems to be restricting the use of Demand interruption for the sake of Firm Transfer reduction. This can be stated directly without adding the confusion of re-dispatch. By coupling re-dispatch with a constraint of not shedding Demand, the paragraph also creates confusion as to what to do in a situation where the amount of Demand that is allowed to be shed in the first paragraph could be reduced with re-dispatch. Would re-dispatch not be allowed? We suggest that the paragraph be rewritten as follows: "Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management)."
Response: The SDT has reorganized the footnote to clarify its intent and address this issue. **b)** An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch,				

Balloter	Company	Seg-ment	Vote	Comment
where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~ ~~-C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~				
Larry Akens	Tennessee Valley Authority	1	Negative	TVA appreciates the SDT's efforts to clarify and improve this complex and challenging area. However, as mentioned in our last comments regarding footnote b, TVA still believes that the SDT's proposal is still focusing more on reliability of local loads than on the overall reliability of the BES. Reliability of local loads should be addressed outside the TPL standards and therefore should not be used/referenced in footnote b. Existing stakeholder processes (referred to in the SDT proposal) typically focus on larger system issues and not on local load serving. TVA believes that some local load should be allowed to be dropped in order to maintain BES reliability. Instead of the proposed footnote b, TVA suggests that the SDT define a "local area" with guidelines detailing the reliability requirements for these local area loads. This would separate the local area load requirements from the BES requirements in the TPL standards.
Ian S Grant	Tennessee Valley Authority	3	Negative	
George T. Ballew	Tennessee Valley Authority	5	Negative	
Marjorie S. Parsons	Tennessee Valley Authority	6	Negative	
Response: The original footnote 'b' focused on local area and limited interruption of Demand. Since individual entities planning philosophies are different across North America, the SDT has been unable to determine a one-size-fits-all definition for local area. Therefore, the SDT adopted an approach that allows entities to utilize input from stakeholders in an open and transparent process. In this way, any affected party has a mechanism to ensure that the planners are planning a reliable BES. No change made.				
Pat G. Harrington	BC Hydro and Power Authority	3	Negative	
Gordon Rawlings	BC Transmission Corporation	1	Negative	
Response: With no comment provided, the SDT is unable to provide a response.				
Gregg R Griffin	City of Green Cove Springs	3	Affirmative	An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will

Balloter	Company	Seg-ment	Vote	Comment
				be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: Interruptible Demand or Demand-Side Management Circumstances where the uses of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.
Response: Thank you for your support.				
Guy V. Zito	Northeast Power Coordinating Council, Inc.	10	Affirmative	1. There is concern with the use of the term Demand. It is unclear throughout the footnote whether or not the term Demand includes Interruptible Demand or Demand-Side Management. It is suggested that interruption of Demand be clarified to not include Interruptible Demand or Demand-Side Management to more clearly show the permitted use of Load shedding. 2. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. 3. Language that mitigation of Load and/or Demand interruption should be pursued within the planning process should be reinstated as reinforcement of a Transmission Providers' planning obligations to their load customers, and system operations. 4. Footnote 'b' should be made to read as follows: b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of Load and/or Demand following Contingency events. Interruption of Load and/or Demand is discouraged and all measures to mitigate such interruption should be pursued within the planning process. However, it is recognized that Load and/or Demand will be interrupted if it is directly served by the elements automatically removed from service by the Protection System as a result of a Contingency. Furthermore, in extraordinary circumstances within the planning process Load and/or Demand may need to be interrupted to address BES performance requirements. When interruption of Load and/or Demand is utilized within the planning

Balloter	Company	Seg-ment	Vote	Comment
				process to address BES performance requirements, such interruption is limited to: • Circumstances where the use of Load and/or Demand interruption are documented, including alternatives evaluated; and where the Load and/or Demand interruption is made available for review in an open and transparent stakeholder process. If Load and/or Demand interruption is necessary, planning should indicate the amount needed, and not specify how it would be obtained. What Load and/or Demand is interrupted is an operational decision. 5. Additional comments not included in the material listed for footnote 'b' on the Comment Form. In the paragraph below the bullets in footnote 'b', confusion is introduced through the use of the term "firm Demand". It is unclear how this is different than the defined term "Firm Demand" and what the implications of the term "firm Demand" are. This footnote should not discourage such adjustments which actually increase the reliability of service to end users. 6. The last sentence of footnote 'b' is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own.

Response: 1. The SDT has reorganized the footnote to clarify its intent and address this issue.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~-C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

2. The SDT has reorganized the footnote to clarify its intent and address the issue raised.

<table>
<tr><th>Balloter</th><th>Company</th><th>Seg-ment</th><th>Vote</th><th>Comment</th></tr>
<tr><td colspan="5">3. & 4. The SDT addressed these concerns by including the phrase “including alternatives evaluated” and does not believe that it is appropriate to dictate that the planners must evaluate “all measures to mitigate” annually or the specific details concerning documentation of alternatives.
5. The SDT has corrected the capitalization errors.
6. Since the planned action of curtailing of firm transfers may adversely impact neighboring systems, the SDT believes that it is important in this situation to articulate a condition that is normally implied. No change made.</td></tr>
<tr><td>Ajay Garg</td><td>Hydro One Networks, Inc.</td><td>1</td><td>Affirmative</td><td rowspan="2">Hydro One is casting an affirmative vote on the revisions to Table 1, footnote ‘b’ in TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. However, we believe the proposed language might be confusing and should be modified to read as follows: “b) It is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Interruptible Demand or Demand-Side Management o Circumstances where the uses of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the interruption of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected.” Note that the voting system does not permit to enter re-lined comments. We can provide a red-lined document with our proposal upon request.</td></tr>
<tr><td>David L Kiguel</td><td>Hydro One Networks, Inc.</td><td>3</td><td>Affirmative</td></tr>
<tr><td colspan="5">Response: The SDT believes that the sentences deleted in your proposed footnote are necessary to provide context for the items that follow and has crafted the language to provide a balance between flexibility and consistency across NERC. The SDT has reorganized the footnote to clarify its intent.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner’s planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

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~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.</td></tr>
</table>

Balloter	Company	Seg-ment	Vote	Comment
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Henry Ernst-Jr	Duke Energy Carolina	3	Affirmative	The effective date in the Implementation Plan needs to be changed to match the Effective Date in the standards, in order to clarify the allowed interruption of Non-consequential load before the new Footnote 'b' takes effect.
Response: The effective dates in the Implementation Plan match those in the standards. No change made.				
Mark B Thompson	Alberta Electric System Operator	2	Abstain	While the AESO does not generally disagree with the intent of the proposed change, we have voted "abstain". In particular, as reflected in the adopted Alberta Reliability Standard TPL-002-AB-0, no loss of Demand and Generation have been given equal consideration for Category B contingencies. In addition, within the Alberta energy market structure and the operation of the transmission system, there are no firm transfers on transmission facilities in Alberta.
Response: Individual jurisdictions are allowed to have more restrictive standards and therefore, this revision to the standard does not dictate that a jurisdiction must change its requirements. The SDT recognizes that there may be areas or markets that do not utilize terms contained within the standard.				

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on TPL Table 1 Order — Project 2010-11

The TPL Table 1 Order Drafting Team thanks all commenters who submitted comments on the 3rd posting for Project 2010-11: TPL Table 1 Order. These standards were posted for a 45-day public comment period from November 19, 2010 through January 5, 2011. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 27 sets of comments, including comments from more than 67 different people from approximately 30 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

The SDT reviewed all of the comments received and has made a clarifying change to the structure of the footnote to address industry concerns as to the intent of the SDT. No contextual changes have been made to the footnote. Therefore, the SDT is recommending that this project be moved to a recirculation ballot.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

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~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

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

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

Index to Questions, Comments, and Responses

The Industry Segments are:

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

Additional Member	Additional Organization	Region	Segment Selection	
1.	Al Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Dean Ellis	Dynegy Generation	NPCC	5
8.	Brian Evans-Mongeon	Utility Services	NPCC	8
9.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	Chantel Haswell	FPL Group, Inc.	NPCC	5
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

14.	Michael R. Lombardi	Northeast Utilities	NPCC	1
15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

				1	2	3	4	5	6	7	8	9	10
2.	Group	Charles W. Long	SERC Planning Standards Subcommittee	X									X

Additional Member	Additional Organization	Region	Segment Selection	
1.	Pat Huntley	SERC Reliability Corporation	SERC	10
2.	Bob Jones	Southern Company Services	SERC	1
3.	Darrin Church	Tennessee Valley Authority	SERC	1
4.	Jim Kelley	PowerSouth Energy Cooperative	SERC	1
5.	John Sullivan	Ameren Services Company	SERC	1
6.	Phil Kleckley	South Carolina Electric & Gas Co.	SERC	1

				1	2	3	4	5	6	7	8	9	10
3.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4.	Jason Marshall	Midwest ISO Inc.	MRO	2
5.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
6.	Ken Goldsmith	Alliant Energy	MRO	4
7.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
8.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Eric Ruskamp	Lincoln Electric System	MRO 1, 3, 5, 6										
10.	Joseph Knight	Great River Energy	MRO 1, 3, 5, 6										
11.	Joe DePoorter	Madison Gas & Electric	MRO 3, 4, 5, 6										
12.	Scott Nickels	Rochester Public Utilties	MRO 4										
13.	Terry Harbour	MidAmerican Energy Company	MRO 1, 3, 5, 6										
14.	Richard Burt	Minnkota Power Cooperative, Inc.	MRO 1, 3, 5, 6										
4.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
5.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
6.	Individual	Andy Tillery	Southern Company	X		X							
7.	Individual	Aaron Staley	Orlando Utilities Commission	X				X					
8.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
9.	Individual	Si Truc PHAN	Hydro-Quebec TransÃ‰nergie	X									
10.	Individual	Tim Ponseti, VP	TVA Trasnmission Plannning & Compliance	X		X		X				X	
11.	Individual	Alex Rost	New Brunswick System Operator		X								
12.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
13.	Individual	Bernie Pasternack	Transmission Strategies, LLC								X		
14.	Individual	Michael A. Curtis, General Counsel	Mohave Electric Cooperative			X							
15.	Individual	David Thorne	Pepco Holding Inc	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
16.	Individual	John Sullivan	Ameren	X		X		X	X				
17.	Individual	Thad Ness	American Electric Power	X		X		X	X				
18.	Individual	Bob Casey	Georgia Transmission Corporation	X									
19.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
20.	Individual	Saurabh Saksena	National Grid	X		X							
21.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
22.	Individual	Jason L. Marshall	Midwest ISO		X								
23.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
24.	Individual	Dan Rochester	Independent Electricity System Operator		X								
25.	Individual	Gregory Campoli	New York Independent System Operator		X								
26.	Individual	Kathleen Goodman	ISO New England Inc		X								
27.	Individual	Harold Wyble	Kansas City Power & Light	X		X		X	X				

1. The SDT is proposing a revision to footnote 'b' in the TPL tables to comply with a FERC directive which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.

Summary Consideration: The SDT reviewed all of the comments received and has made a clarifying change to the structure of the footnote to address industry concerns as to the intent of the SDT. No contextual changes have been made to the footnote.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized [llh1]that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

Organization	Yes or No	Question 1 Comment
SERC Planning Standards Subcommittee	No	The PSS agrees that the proposed language for footnote b provides some additional clarity. While we generally support the concept, we have concerns that the phrase "is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments" remains ambiguous and should be clarified by limiting stakeholder input to those who have load at risk or local regulators obligated to

Organization	Yes or No	Question 1 Comment
		act on their behalf. Revise the first sentence of the last paragraph to read: “To prepare for a second contingency, curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand.”The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Response: The stakeholder process needs to be open and transparent but it is up to the entity to establish the process and whom it may include. No change made. As drafted, footnote ‘b’ clarifies that re-dispatch is allowable to “remain within” ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can only be utilized for a limited time, such as a 2 hour emergency rating. It further clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the firm transfers cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words “To prepare for the next Contingency” to the footnote. No change made.		
Xcel Energy	No	As this is currently drafted, planners would be required to host a forum with stakeholders to discuss hypothetical actions that may be taken in an emergency. We do not see the value in this, nor is it clear who would be considered stakeholders that should attend this forum. For example, we assume it would be the transmission owner’s meeting with distribution providers to discuss the possibility of load shedding. Would that be adequate? Xcel Energy is both a Transmission Planner and a Distribution Provider. In this case would the stakeholder be the end user? This should be struck or more clearly defined.
Response: The stakeholder process needs to be open and transparent but it is up to the entity to establish the process and whom it may include. No change made.		
New York Independent System Operator	No	1. Proposed revised footnote language:b) It is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Interruptible Demand or Demand-Side Management o Circumstances where the uses of firm Demand interruption not directly interrupted by the contingency are documented, including alternatives evaluated; and where the firm Demand interruption is subject to review in an open and transparent stakeholder process. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities

Organization	Yes or No	Question 1 Comment
		remain within applicable Facility Ratings and the re-dispatch does not result in the interruption of any firm Demand. 2. Comments:There are generic concerns with the footnote as amended that must be addressed. The first is the use of the term “Demand”. It is very unclear throughout the footnote whether or not the term Demand includes Interruptible Demand or Demand-Side Management. It is suggested that interruption of Demand be clarified to not include Interruptible Demand or Demand-Side Management to more clearly show the permitted use of that option for load shedding. 3. Further confusion is introduced through the use of the term “firm Demand” in some locations. It is unclear how this is different than the defined term “Firm Demand” and what the implications of the term “firm Demand” are. 4. The first and third sentences of the first paragraph are unnecessary and should be deleted. However, if they are to be retained, the first sentence is unacceptable in its current state. In some instances, Interruptible Demand or Demand-Side Management are utilized in lieu of transmission additions. These can be considered as acceptable mitigation and there is no justification to minimize their use. Therefore some clarification to the term Demand in the first sentence must be made. 5. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. 6. The second portion of the second bullet should be deleted as it is unncessary: “and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.” If this is to be retained, the very last portion should be deleted “that includes addressing stakeholder comments”. The term “addressing” is unclear. This can be misconstrued to infer that plans must be changed in response to stakeholder comments. This may be inappropriate and may be impossible if conflicting comments are received. It may also create a new standard that all comments must be “addressed”, which may not be a part of the stakeholder process across NERC’s footprint. 7. The first sentence of the paragraph under the two bullets seems to prevent a situation where a combination of re-dispatch and the interruption of Demand are utilized. This restriction could prevent a situation where the use of re-dispatch decreases the amount of Demand which must be interrupted. This footnote should not discourage such adjustments which actually increase the reliability of service to end users. 8. This same sentence also uses the term “shedding of firm Demand”. This should be replaced with “Demand interruption” such that it is consistent with the second bullet; otherwise an unnecessary new term has been introduced.

Organization	Yes or No	Question 1 Comment
		9. The last sentence of footnote B is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple NERC standards if it was added here, otherwise it would infer that such actions are acceptable in all other standards.

Response: 1. See response to National Grid #1 in ballot comment responses.

2. See response to National Grid #1 in ballot comment responses.

3. See response to National Grid #6 in ballot comment responses.

4. The SDT has reorganized the footnote to clarify its intent and address the issues raised.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

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~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result~~ [llh2]~~in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

5. See response to National Grid #2 in ballot comment responses.

6. See response to National Grid #4 in ballot comment responses.

7. The SDT has reorganized the footnote to clarify its intent and address the issues raised.

8. The SDT has reorganized the footnote to clarify its intent and address the issues raised.

Organization	Yes or No	Question 1 Comment
9. See response to National Grid #7 in ballot comment responses.		
ISO New England Inc	No	1. The following comments are provided in regard to this proposal. The first and third sentences of the first paragraph are unnecessary. While we agree with the concept, it is unclear as to how inclusion of these sentences in a standard creates a measureable requirement. 2. There are generic concerns with the footnote as currently proposed. The first is the use of the term "Demand." It is unclear whether the term Demand includes Interruptible Demand and Demand-Side Management. It is suggested that interruption of Demand be clarified to exclude Interruptible Demand and Demand-Side Management to more clearly show the permitted use of those options. 3. The second concern is that it is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. 4. The third is that not all areas have stakeholder processes. Documenting the use of Demand Interruption should be sufficient without requiring stakeholder review. Therefore the second portion of the second bullet "including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments" is unnecessary and should be deleted. "Addressing stakeholder comments" introduces undefined actions which may be required in response to the comments. For those areas that already have stakeholder processes, stakeholder comments are by definition addressed. As a result, at a minimum "that includes addressing stakeholder comments" should be deleted. Furthermore, for areas that do not have stakeholder processes, so long as they publish their studies impacted parties are aware of the role of demand response. 5. The fourth is that the second paragraph seems to be restricting the use of Demand interruption for the sake of Firm Transfer reduction. This can be stated directly without adding the confusion of re-dispatch. By coupling re-dispatch with a constraint of not shedding Demand, the paragraph also creates confusion as to what to do in a situation where the amount of Demand that is allowed to be shed in the first paragraph could be reduced with re-dispatch. Would re-dispatch not be allowed? We suggest that the paragraph be rewritten as follows: "Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management)." 6. The fifth is if the term 'firm demand' survives the proposed changes; is there an intended distinction between the use of the term "firm Demand" and the defined term "Firm Demand"? If these terms are intended to be differently, it is unclear what the term "firm Demand" represents. 7. The final comment is that the last sentence of footnote B is unnecessary and should be deleted. It is

Organization	Yes or No	Question 1 Comment
		never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple NERC standards if it was added here, otherwise it would infer that such actions are acceptable in all other standards. 8. If the first and third sentences must be retained the following wording for the footnote is proposed:b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand, (excluding Interruptible Demand or Demand-Side Management), following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Interruptible Demand or Demand-Side Management o Circumstances where the uses of Demand interruption not directly interrupted by the contingency are documented. Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management).

Response: 1. The SDT believes that the first part of the footnote is necessary to provide context for the items that follow and has crafted the language to provide a balance between flexibility and consistency across NERC. No change made.

2. See ballot response to NPCC #1.

3. See ballot response to NPCC #2.

4. The SDT believes that in situations where an entity's planning studies require the interruption of firm load to remain within BES Facility ratings that the entity needs to share those plans in an open and transparent stakeholder process to ensure that other parties that may be adversely impacted by those decisions have the ability to review and comment on those plans. No change made.

5. See ballot response to NPCC #5.

6. The SDT has corrected the indicated errors.

7. See ballot response to NPCC #6.

8. The SDT has reorganized the text in the footnote to address this concern.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited

Organization	Yes or No	Question 1 Comment
circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~		
Northeast Power Coordinating Council	No	There is concern with the use of the term Demand. It is unclear throughout the footnote whether or not the term Demand includes Interruptible Demand or Demand-Side Management. It is suggested that interruption of Demand be clarified to not include Interruptible Demand or Demand-Side Management to more clearly show the permitted use of Load shedding. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. Language that mitigation of Load and/or Demand interruption should be pursued within the planning process should be reinstated as reinforcement of a Transmission Providers' planning obligations to their load customers, and system operations. Footnote 'b' should be made to read as follows:b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of Load and/or Demand following Contingency events. Interruption of Load and/or Demand is discouraged and all measures to mitigate such interruption should be pursued within the planning process. However, it is recognized that Load and/or Demand will be interrupted if it is directly served by the elements automatically removed from service by the Protection System as a result of a Contingency. Furthermore, in extraordinary circumstances within the planning process Load and/or Demand may need to be interrupted to address BES performance requirements. When interruption of Load and/or Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Circumstances where the use of Load and/or Demand interruption are documented, including alternatives evaluated; and where the Load and/or Demand interruption is made available for review in an open and transparent stakeholder process.If Load and/or Demand interruption is necessary, planning should indicate the amount needed, and not specify how it would be obtained. What Load and/or Demand is

Organization	Yes or No	Question 1 Comment
		interrupted is an operational decision. Additional comments not included in the material listed for footnote ‘b’ on the Comment Form. In the paragraph below the bullets in footnote ‘b’, confusion is introduced through the use of the term “firm Demand”. It is unclear how this is different than the defined term “Firm Demand” and what the implications of the term “firm Demand” are. This footnote should not discourage such adjustments which actually increase the reliability of service to end users. The last sentence of footnote ‘b’ is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own.
Response: This comment is identical to the one made by NPCC in the ballot and the SDT has answered the comment in that forum.		
Arizona Public Service Company	No	It is not clear whether both bullets under "footnote b" have to be met or only one of the two have to be met. It is suggested that the standard be very clear about this.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Southern Company	No	Southern Company is voting "no" on the footnote b ballot because of concerns that the reliability of firm transfers could be compromised. The existing Table I Transmission System Standards, which have been in place as early as the 1997 NERC Planning Standards, do not allow Loss of Demand or Curtailed Firm Transfers under single (Category B) contingencies. Footnote B addressed two areas: 1) the loss of radial or local network load, which Southern Company agrees that the drafting team has appropriately clarified and 2) preparing for the next contingency, which Southern Company does not agree has been appropriately clarified.Southern Company believes the proposed wording "Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch" now allows for the curtailment of firm transfers for single contingencies, whereas Southern Company did not believe this was previously permitted under the standards. Southern Company interprets the new language to allow a planner to curtail firm transfers (generation) to address a single contingency. Southern Company interpreted the original language to not permit the curtailment of firm transfers (generation) for a single contingency, but rather that a planner would develop a suitable transmission reinforcement or other mitigation. Southern Company is concerned that the proposed language could result in a degradation in the dependability of firm transfers impacting the reliability of those customers who rely upon them. Southern Company agrees that a system reconfiguration including the redispatch of generation is appropriate when preparing for a second contingency (Category C).Therfore, a distinction is needed between what is allowed in response to a first contingency and what is allowed to be prepared for a second contingency. The curtailment of firm transfers should not be allowed as a response to the first contingency. This practice would undermine the concept of firm transfers. The curtailment of firm transfers should only be allowed in footnote b as a system adjustment to be prepared for a second contingency. We propose the following to clarify that curtailments are permitted only to prepare

Organization	Yes or No	Question 1 Comment
		for the second contingency. "To prepare for the next contingency, curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch".
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Orlando Utilities Commission	No	The current language provides a balance between the end goal of reliablity (no load loss for B events) and the practical constraint that project cost may outweigh the benefit. Two things are unclear though. Item one: The standard team should clarify if the bullets under note B are intended to be an AND (both conditions met) or an OR (either condition met). As currently written it is not clear. Item #2: The section under firm transfers is in conflict with the section above. If Demand is being curtailed under the first or second bullet and it's served by firm service then service should also be curtailed, however as written any demand served by firm service could not be curtailed.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Duke Energy	Yes	The effective date in the Implementation Plan needs to be changed to match the Effective Date in the standards, in order to clarify the allowed interruption of Non-consequential load before the new Footnote 'b' takes effect.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Hydro-Quebec Transenergie	Yes	Paragraph should be more clear as:b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances within the planning process, Demand may need to be interrupted to address BES performance requirements. In such case : o Only Interruptible Demand or Demand-Side Management are allowed;o Circumstances where the uses of Demand interruption is needed shall be documented, compared to alternatives, and reviewed in an open and transparent stakeholder process that address stakeholder comments. Curtailment of firm transfers is allowed, when coupled with the appropriate and necessary re-dispatch of resources where it can be demonstrated that this does not result in the shedding of any firm Demand and that Facilities remain within applicable Facility Ratings, including Facilities external to the Transmission Planner's planning region when they are relied upon.
Response: The SDT believes that the changes indicated in your proposed footnote do not add any additional clarity. However, the SDT has reorganized the footnote to clarify its intent.		

Organization	Yes or No	Question 1 Comment
b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~ ~~Interruptible Demand or Demand-Side Management~~ ~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. ~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~		
TVA Trasnmission Plannning & Compliance	No	TVA appreciates the SDT's efforts to clarify and improve this complex and challenging area. However, as mentioned in our last comments regarding footnote b, TVA still believes that the SDT's proposal is still focusing more on reliability of local loads than on the overall reliability of the BES. Reliability of local loads should be addressed outside the TPL standards and therefore should not be used/referenced in footnote b. Existing stakeholder processes (referred to in the SDT proposal) typically focus on larger system issues and not on local load serving. TVA believes that some local load should be allowed to be dropped in order to maintain BES reliability. Instead of the proposed footnote b, TVA suggests that the SDT define a "local area" with guidelines detailing the reliability requirements for these local area loads. This would separate the local area load requirements from the BES requirements in the TPL standards.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
New Brunswick System Operator	No	NBSO agrees with the principles of the current version of the proposed footnote, as far as NBSO's interpretation of the footnote is correct. NBSO has the following detailed comments:1. The first paragraph contains many general statements that attempts to capture essential planning principles. NBSO feels that such language is not suited for a footnote. NBSO suggests re-wording of the first paragraph to state:Interruption of Demand may be utilized within the planning process to address BES performance requirements. Such cases are limited to:NBSO also suggests turning the phrase that addresses Demand lost that was served by elements removed from service as a result of a Contingency into a bullet item. NBSO feels

Organization	Yes or No	Question 1 Comment
		that this adds clarity since all of the acceptable instances of Demand interruption are now listed as bulleted items.2. NBSO interprets that the currently proposed footnote allows for the two bulleted options to be used exclusively or in combination. Thus for clarification NBSO suggests adding “or” after each bulleted item, with the exclusion of the final bulleted item.3. NBSO suggests removing the last sentence of the last paragraph. Likely all industry members understand that causing reliability concerns in other areas is never acceptable. This principle is not limited to the standard in question, and thus such a statement could require the update of other standards.4. NBSO interprets that the use of the word “Demand” in the second bullet of the proposed footnote is referring to use of Firm Demand since the first bullet covers the other types of Demand (Demand = Firm Demand + Interruptible Demand). As such NBSO suggests replacing “Demand” with “Firm Demand” in the second bullet.5. NBSO feels that the statement “that includes addressing stakeholder comments” should be removed from the last phrase of the second bullet. An open and transparent stakeholder process should adequately address stakeholder comments and concerns. Explicitly specifying that all stakeholder comments be addressed may add undue burden if the word “address” is misconstrued. The task of addressing stakeholder comments is more appropriately addressed and defined in each area’s respective process.6. NBSO suggests replacing the word “shedding” with “interruption” in the last phrase of the last paragraph to remain consistent with the rest of the proposed footnote. NBSO also suggests capitalizing “firm” in the term “Firm Demand” to remain consistent with the NERC glossary of terms.7. There is no term “transfers” in the NERC glossary of terms. Perhaps some other defined term from the glossary could be used in lieu of “transfers” (e.g. Firm Transmission Service).Taking into account the NBSO comments, the footnote could read as follows:b) Interruption of Demand may be utilized within the planning process to address BES performance requirements. Such cases are limited to:-Demand directly served by Elements removed from service as a result of a Contingency, or-Use of Interruptible Demand or Demand-Side Management, or-Interruption of Firm Demand when acceptable circumstances for such interruptions are documented (including alternatives evaluated), and where the Firm Demand interruption is subject to review in an open and transparent stakeholder process.Curtailment of Firm Transmission Service is allowed when coupled with the appropriate re-dispatch of resources obligated to do so, and it can be demonstrated that Facilities remain within applicable Facility Ratings and there is no additional interruption of Firm Demand.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Manitoba Hydro	No	The last bullet should be made clearer by adding the words “in jurisdictions” before the word “where”. Not all jurisdictions are mandated to have a stakeholder process, so the standard should be clearly written to recognize this situation. "Circumstances where the use of Demand interruption are documented, including alternatives evaluated; and IN JURISDICTIONS where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments."

Organization	Yes or No	Question 1 Comment
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Ameren	No	We agree with the statement that an objective of the planning process should be to minimize the likelihood and magnitude of interruption of Demand following single contingency events. While we appreciate the drafting team's efforts in removing the need for acceptance by other parties in the stakeholder process, we still feel that language in the second bullet of the revised footnote b should be modified to remove all references to an open and transparent stakeholder process. Existing RTO stakeholder processes that we are aware of focus on larger system issues, rather than on local load serving issues. Therefore, we believe that the load serving issues following single contingency events are issues between the customer and the utility, and should be addressed in one-on-one forums between those entities.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
National Grid	No	National Grid supports the direction the drafting team has taken. However, it has a few concerns with the language of the footnote as amended. 1. Use of the term "Demand": In the first sentence, it is unclear whether the term Demand includes Interruptible Demand and Demand-Side Management. It is suggested that interruption of Demand be clarified to exclude Interruptible Demand or Demand-Side Management. 2. It is unclear whether the second bullet includes Demand which is interrupted by the elements removed from service. Clarification should be made such that Demand which is interrupted by the elements removed from service should not be included in this bullet. 3. National Grid also suggests changing "Demand interruption" to "interruption of Demand" in second bullet under "b)" to avoid awkward and incorrect phasing.4. 'Addressing stakeholder comments' introduces undefined actions which may be required in response to the comments. If 'Demand interruption is subject to review in an open and transparent stakeholder process', then stakeholder comments will be addressed without creating an undefined commitment to require it. As a result, "that includes addressing stakeholder comments" should be deleted. 5. The second paragraph seems to be restricting the use of Demand interruption for the sake of Firm Transfer reduction. This can be stated directly without adding the confusion of re-dispatch. By coupling re-dispatch with a constraint of not shedding Demand, the paragraph also creates confusion as to what to do in a situation where the amount of Demand that is allowed to be shed in the first paragraph could be reduced with re-dispatch. Would re-dispatch not be allowed? National Grid suggests that the paragraph be rewritten as follows: 'Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management).' 6. National Grid seeks clarification if there is an intended distinction between the use of the term "firm Demand" and the defined term "Firm Demand" or is that just a typo?7. The last sentence of footnote B is unnecessary and should be deleted. It is never acceptable to cause reliability concerns in another area while addressing your own. This same thought would have to be added to multiple

Organization	Yes or No	Question 1 Comment
		NERC standards if it were added here, otherwise it would infer that such actions are acceptable in all other standards.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Northeast Utilities	No	The revised language of Footnote b suggests that non-consequential demand interruption (load that is not directly served by the elements removed from service as a result of the contingency) could be used to mitigate reliability concerns arising from NERC Category B contingency events (i.e., single element contingencies). This language seems to encourage operational workarounds and adds burdens for operators of the system. NU believes this is not consistent with planning a highly reliable bulk electric system and thus does not support this weaker language.
Response: This comment is identical to one made in the ballot and the SDT has answered the comment in that forum.		
Kansas City Power & Light	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
PacifiCorp	Yes	appreciates the efforts of the SDT and supports revision of TLP-002-0 Table 1 footnote “b” as stated in this draft.
Transmission Strategies, LLC	Yes	
Mohave Electric Cooperative	Yes	
Pepco Holding Inc	Yes	
American Electric Power	Yes	
Georgia Transmission Corporation	Yes	
American Transmission Company	Yes	

Organization	Yes or No	Question 1 Comment
Midwest ISO	Yes	
Independent Electricity System Operator	Yes	
Response: Thank you for your support.		

Implementation Plan for Project 2010-11: TPL Table 1 Order

Prerequisite Approvals

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

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed standards.

Compliance with Standards

Standards	**Functions That Must Comply With the Associated Requirements**	
	Transmission Planner	Planning Authority
TPL-001-0.2: System Performance Under Normal (No Contingency) Conditions (Category A) TPL-002-0c: System Performance Following Loss of a Single Bulk Electric System Element (Category B) TPL-003-0b: System Performance Following Loss of Two or More Bulk Electric System Elements (Category C) TPL-004-0a: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

The effective date for footnote ‘b’ will be the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption.

All other requirements remain in effect as per previous approvals.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Standards re-posted in September 2010.
6. Re-balloted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT’s intent. The SDT responded to these requests by re-ordering the items in footnote ’b’ to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Recirculation ballot	January 2011
2. Submit to BOT for approval	January 2011
3. File with FERC	February 2011

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-1

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-1_R1 and TPL-001-1_ R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Compliance Monitor: Regional Reliability Organization.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame
Annually

1.3. Data Retention
None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner’s planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Standards re-posted in September 2010.

~~4.~~6. Re-ballotted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT’s intent. The SDT responded to these requests by re-ordering the items in footnote ’b’ to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	Anticipated Date
~~1. 30-day posting~~	~~September 2010~~
~~2. 30-day pre-ballot period~~	~~November 2010~~
~~3. Initial ballot~~	~~December 2010~~
1. ~~4.~~ Recirculation ballot	January 2011
2. ~~5.~~ Submit to BOT for approval	January 2011
3. ~~6.~~ File with FERC	February 2011

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-1

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-1_R1 and TPL-001-1_ R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

	Contingencies	System Limits or Impacts

Category	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple)	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 3. Transformer	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and

elements removed or Cascading out of service.	2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is

due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Standards re-posted in September 2010.
6. Re-balloted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT’s intent. The SDT responded to these requests by re-ordering the items in footnote ’b’ to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	**Anticipated Date**
1. Recirculation ballot	January 2011
2. Submit to BOT for approval	January 2011
3. File with FERC	February 2011

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-~~0.~~1

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

~~5. **Effective Date:** May 13, 2009~~

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-~~0~~1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. **Measures**

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-~~0~~1_R1 and TPL-001-~~0~~1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-~~0~~1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Compliance Monitor: Regional Reliability Organization.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame
Annually

1.3. Data Retention
None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised

~~Table I. Transmission System Standards – Normal and Emergency Conditions~~

~~Category~~1	~~Contingencies~~TBD	~~System Limits or Impacts~~Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised

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Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is

due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Standards re-posted in September 2010.
6. Re-balloted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT’s intent. The SDT responded to these requests by re-ordering the items in footnote ’b’ to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Recirculation ballot	January 2011
2. Submit to BOT for approval	January 2011
3. File with FERC	February 2011

A. Introduction

1. **Title:** **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. **Number:** TPL-002-1b

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Standards re-posted in September 2010.
6. ~~4.~~ Re-ballotted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote 'b' to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT's intent. The SDT responded to these requests by re-ordering the items in footnote 'b' to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	Anticipated Date
~~1. 30-day posting~~	~~September 2010~~
~~2. 30-day pre-ballot period~~	~~November 2010~~
~~3. Initial ballot~~	~~December 2010~~
~~4~~1. Recirculation ballot	January 2011
2. Submit to BOT for approval	January 2011
3. File with FERC	February 2011

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-1b

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Standards re-posted in September 2010.
6. Re-balloted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote 'b' to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT's intent. The SDT responded to these requests by re-ordering the items in footnote 'b' to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	**Anticipated Date**
1. Recirculation ballot	January 2011
2. Submit to BOT for approval	January 2011
3. File with FERC	February 2011

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-~~0b~~1b

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

~~**5. Effective Date:** Immediately after approval of applicable regulatory authorities.~~

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories~~,~~, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-~~0~~1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-~~0~~1_R1 and TPL-002-~~0~~1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-~~0~~1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating[a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No[b] No[b] No[b] No[b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2
Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Standards re-posted in September 2010.
6. Re-balloted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT’s intent. The SDT responded to these requests by re-ordering the items in footnote ’b’ to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Recirculation ballot	January 2011
2. Submit to BOT for approval	January 2011
3. File with FERC	February 2011

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-1a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-1_R1 and TPL-003-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information
None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
1a	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

<table>
<tr>
<td>D [d]

Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</td>
<td>3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure):
1. Generator
2. Transmission Circuit
3. Transformer
4. Bus Section
<hr>3Ø Fault, with Normal Clearing[e]:
5. Breaker (failure or internal Fault)
<hr>6. Loss of towerline with three or more circuits
7. All transmission lines on a common right-of way
8. Loss of a substation (one voltage level plus transformers)
9. Loss of a switching station (one voltage level plus transformers)
10. Loss of all generating units at a station
11. Loss of a large Load or major Load center
12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required
13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate
14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</td>
<td>Evaluate for risks and consequences.
▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.
▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.
▪ Evaluation of these events may require joint studies with neighboring systems.</td>
</tr>
</table>

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Standards re-posted in September 2010.
6. ~~4.~~ Re-ballotted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
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These changes were balloted and received approval but several commenters requested clarifications of the SDT’s intent. The SDT responded to these requests by re-ordering the items in footnote ’b’ to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	Anticipated Date
~~1. 30-day posting~~	~~September 2010~~
~~2. 30-day pre-ballot period~~	~~November 2010~~
~~3. Initial ballot~~	~~December 2010~~
1.~~4.~~ Recirculation ballot	January 2011
2.~~5.~~ Submit to BOT for approval	January 2011
3.~~6.~~ File with FERC	February 2011

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-1a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

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R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-1_R1 and TPL-003-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
1a	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) ~~-~~directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements,, such interruption is limited to~~:~~

~~o Interruptible Demand or Demand-Side Management~~

~~-C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected~~

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Standards re-posted in September 2010.
6. Re-balloted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT’s intent. The SDT responded to these requests by re-ordering the items in footnote ’b’ to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	**Anticipated Date**
1. Recirculation ballot	January 2011
2. Submit to BOT for approval	January 2011
3. File with FERC	February 2011

A. Introduction

1. Title: System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)

2. Number: TPL-003-~~0a~~1a

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

~~**5. Effective Date:** April 23, 2010~~

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-~~0~~1 R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-~~0~~1 R1 and TPL-003-~~0~~1 R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-~~0~~1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item "e" on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
~~0a~~1a	~~April 23, 2010~~TBD	~~FERC approval of interpretation of TPL-003-0 R1.3.12~~Revised footnote 'b' pursuant to FERC Order RM06-16-009.	~~Interpretation~~Revised

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Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12
Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12
Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Standards re-posted in September 2010.
6. Re-balloted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote 'b' allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote 'b' were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term 'fringes' was seen as problematic and application at the 'fringes' could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote 'b'. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote 'b' in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT’s intent. The SDT responded to these requests by re-ordering the items in footnote ’b’ to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Recirculation ballot	January 2011
2. Submit to BOT for approval	January 2011
3. File with FERC	February 2011

A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. **Number**: TPL-004-1

3. **Purpose**: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability**:

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

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3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Standards re-posted in September 2010.
6. ~~4.~~Re-ballotted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote 'b' to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT's intent. The SDT responded to these requests by re-ordering the items in footnote 'b' to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	Anticipated Date
~~1. 30-day posting~~	~~September 2010~~
~~2. 30-day pre-ballot period~~	~~November 2010~~
~~3. Initial ballot~~	~~December 2010~~
~~4~~1. Recirculation ballot	January 2011
~~5~~2. Submit to BOT for approval	January 2011
~~6~~3. File with FERC	February 2011

A. Introduction

1. Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. Number: TPL-004-1

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-1_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-1_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D[d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~However, i~~It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to~~:~~

~~Interruptible Demand or Demand-Side Management~~

~~C~~circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

~~Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.~~

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR submitted to SC in April 2010.
2. SAR approved by SC in April 2010.
3. 30-day pre-ballot period completed in May 2010.
4. Initial ballot completed in May 2010.
5. Standards re-posted in September 2010.
6. Re-balloted in December 2010.

Proposed Action Plan and Description of Current Draft:

The SAR for this project proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Such clarification was originally required by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards. (Note: FERC issued a clarifying order on June 11, 2010 which extended the deadline for clarifying Table 1 until March 31, 2011.)

Based on stakeholder comments, the drafting team has made changes from the initial ballot posting to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

While the initial ballot results came close to the required approval percentage, it was clear to the SDT that there were still a number of concerns with the proposed clarification. In particular, entities were concerned that the proposal was still unclear and too limiting on the proposed conditions when Demand could be interrupted. Also, there were numerous concerns raised on jurisdictional issues with regard to interrupting Demand. In short, the needed clarification hadn't been achieved. Therefore, the SDT continued discussions on different alternatives to address the needed clarification. This led the SDT to focus on identifying constraining parameters such as the amount of Demand that could be interrupted, annual amount of exposure, etc.

In order to receive additional industry feedback on the new approach, a Technical Conference was held on August 10, 2010 to address four specific questions arising from the FERC June 11, 2010 clarification order. These 4 questions were:

1. Under what circumstances do you believe the existing footnote ‘b’ allows an entity to plan to shed non-consequential firm load for a single contingency (Category B)? Please provide specific information to the extent possible.
2. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be applied at the fringes of a system. Is this limitation appropriate and if so, please define it? What other specific criteria could be applied to limit the planned use of non-consequential firm load loss for a single contingency (Category B)?
3. If footnote ‘b’ were re-stated such that there would be no planned loss of non-consequential firm load allowed for a single contingency event (Category B), what changes to your transmission plan would be required? Please quantify your response to the extent possible.
4. The June 11th order from FERC suggested that planning to shed non-consequential firm load for a single contingency (Category B) could be handled on a case-by-case basis with affected entities asking for an exception from the ERO. Could you support such a process? If your response is no, then what process would you suggest? If your response is yes, then what technical criteria should be developed to identify and evaluate cases?

In summary, the SDT heard that:

- Industry feels that interrupting non-consequential Demand was appropriate in certain limited circumstances and that such usage was not widespread.
- Use of the term ‘fringes’ was seen as problematic and application at the ‘fringes’ could possibly be discriminatory.
- If interruption of non-consequential Demand was not allowed, such a policy would result in significant costs to customers for limited benefits.
- A case-by-case exception process that required ERO or FERC approval was not viewed as an acceptable approach due to possible inconsistencies in approach and potential unacceptable delays.

The SDT took in all of these inputs and returned to their deliberations attempting to leverage the existing work with the industry comments to develop an acceptable clarification to footnote ‘b’. This led to the approach shown in this posting where the SDT has taken the concept of allowing interruption of Demand without numerical constraints in an open and transparent stakeholder process to review and accept such plans. This open and transparent stakeholder process is seen as an enhancement of existing entity processes without the problems associated with an ERO or FERC case-by-case exception process.

The SDT believes that this approach addresses industry concerns and FERC Order 693 directives (and subsequent orders) concerning clarification to footnote ‘b’ in a way that is an equal and effective method and that should be acceptable to all concerned parties.

In addition, the following bullet was added to Footnote ‘b’ to clarify that it is always acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

These changes were balloted and received approval but several commenters requested clarifications of the SDT’s intent. The SDT responded to these requests by re-ordering the items in footnote ’b’ to make it clear exactly what the intent of the changes were.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Recirculation ballot	January 2011
2. Submit to BOT for approval	January 2011
3. File with FERC	February 2011

A. Introduction

1. Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. Number: TPL-004-~~0~~1

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

~~**5. Effective Date:** April 1, 2005~~

5. Effective Date: The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority’s and Transmission Planner’s assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-~~0~~1 R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-~~0~~1 R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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RELIABILITY CORPORATION

Standards Announcement

Recirculation Ballot Window Open January 26-February 5, 2011
Project 2010-11 TPL Table 1 Order

Now available at: https://standards.nerc.net/CurrentBallots.aspx

A recirculation ballot window for standards TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1 is open **until 8 p.m. Eastern on Saturday, February 5, 2011**.

Instructions
Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx.

Ballot Process
The Standards Committee encourages all members of the ballot pool to review the consideration of comments submitted during the last ballot window. In the recirculation ballot, votes are counted by exception only — if a ballot pool member does not submit a revision to that member's original vote, the vote remains the same as in the first ballot. Members of the ballot pool may:

- Reconsider and change their votes from the first ballot
- Vote in the second ballot even if they did not vote on the first ballot
- Take no action if they do not want to change their original vote

Additional Information
The Standard Processes Manual allows drafting teams to make changes following an initial or successive ballot with a goal of improving the quality of a standard, provided those changes do not alter the applicability or scope of the proposed standard. Following the initial ballot the Project 2010-11 made minor changes to the structure of footnote 'b' in all of the standards, and corrected capitalization of NERC Glossary terms. The standards (clean versions, and redlines against the last posted and last approved versions) have been posted on the project page.

Next Steps
Voting results will be posted and announced after the ballot window closes. If approved, the standards and associated implementation plan will be submitted to the Board of Trustees.

Background
FERC Order RM06-16-009 requires the ERO to clarify TPL-002-0, Table 1 - footnote 'b,' regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system and originally directed NERC to file the revised standards by June 30, 2010. To meet this directive, a proposed revision was posted for "Urgent Action" and balloted from May 17-27, 2010. The proposed revision

achieved a quorum (84%) and almost enough affirmative votes (64%) to achieve weighted segment approval; however many balloters provided comments indicating the need for additional modifications. Following the initial ballot, FERC extended the due date to March 31, 2011; thus the project is no longer considered "Urgent Action."

Because Table 1 appears in TPL-001, TPL-002, TPL-003, and TPL-004, the change is reflected in all four standards:

- TPL-001-1 - System Performance Under Normal (No Contingency) Conditions (Category A)
- TPL-002-1b - System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- TPL-003-1a - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
- TPL-004-1 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

More details may be found on the project page:
http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

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Standards Announcement

Project 2010-11 TPL Table 1, Footnote B
Recirculation Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

A recirculation ballot of Table 1 footnote 'b' in TPL-001-1 through TPL-004-1 ended on February 5, 2011. The standards were approved. Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 93.61 %
Approval: 86.54 %

Background:

FERC Order RM06-16-009 requires the ERO to clarify TPL-002-0, Table 1 - footnote 'b,' regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system, and originally directed NERC to file the revised standards by June 30, 2010. To meet this directive a proposed revision was posted for "Urgent Action" and balloted from May 17-27, 2010. The proposed revision achieved a quorum (84%) and almost enough affirmative votes (64%) to achieve weighted segment approval; however many balloters provided comments indicating the need for additional modifications. Following the initial ballot, FERC extended the due date to March 31, 2011, thus the project is no longer considered "Urgent Action."

Because Table 1 appears in TPL-001, TPL-002, TPL-003, and TPL-004, the change is reflected in all four standards:

- TPL-001-1 - System Performance Under Normal (No Contingency) Conditions (Category A)
- TPL-002-1b - System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- TPL-003-1a - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
- TPL-004-1 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

More details may be found on the project page:
http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Next Steps

The standards will go to the Board of Trustees for adoption.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

Ballot Results	
Ballot Name:	Project 2010-11 TPL Table 1 Footnote B SAR_rc
Ballot Period:	1/26/2011 - 2/5/2011
Ballot Type:	recirculation
Total # Votes:	293
Total Ballot Pool:	313
Quorum:	**93.61 % The Quorum has been reached**
Weighted Segment Vote:	86.54 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

			Affirmative		Negative		Abstain	
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**# Votes**	**No Vote**
1 - Segment 1.	95	1	68	0.829	14	0.171	7	6
2 - Segment 2.	11	1	7	0.7	3	0.3	1	0
3 - Segment 3.	66	1	50	0.833	10	0.167	5	1
4 - Segment 4.	26	1	16	0.889	2	0.111	6	2
5 - Segment 5.	58	1	40	0.851	7	0.149	5	6
6 - Segment 6.	37	1	28	0.875	4	0.125	3	2
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.5	5	0.5	0	0	1	2
9 - Segment 9.	4	0.4	4	0.4	0	0	0	0
10 - Segment 10.	8	0.7	7	0.7	0	0	0	1
Totals	**313**	**7.6**	**225**	**6.577**	**40**	**1.023**	**28**	**20**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Affirmative	View
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	APS	Barbara McMinn	Affirmative	
1	Arizona Public Service Co.	Robert D Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	

1	Avista Corp.	Scott Kinney	Affirmative	View
1	BC Transmission Corporation	Gordon Rawlings	Negative	View
1	Beaches Energy Services	Joseph S. Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	CenterPoint Energy	Paul Rocha	Abstain	
1	Central Maine Power Company	Kevin L Howes	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Vero Beach	Randall McCamish	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Abstain	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	View
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker	Affirmative	View
1	Dominion Virginia Power	John K Loftis	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils		
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	GDS Associates, Inc.	Claudiu Cadar	Negative	
1	Georgia Transmission Corporation	Harold Taylor, II	Negative	View
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	View
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stan T. Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Lone Star Transmission, LLC	Julius Horvath	Affirmative	View
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	View
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	National Grid	Saurabh Saksena	Affirmative	
1	Nebraska Public Power District	Richard L. Koch	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	View
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David H. Boguslawski	Negative	View
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Douglas G Peterchuck	Affirmative	
1	Oncor Electric Delivery	Michael T. Quinn	Abstain	
1	Orlando Utilities Commission	Brad Chase	Negative	View
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	View
1	PacifiCorp	Colt Norrish	Affirmative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	

1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Linda Brown	Negative	View
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Negative	View
1	Southern Illinois Power Coop.	William G. Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	View
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young	Affirmative	View
1	Tennessee Valley Authority	Larry Akens	Negative	View
1	Tri-State G & T Association, Inc.	Keith V Carman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Negative	View
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	View
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Abstain	View
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	View
2	California ISO	Gregory Van Pelt	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Jason L Marshall	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Negative	View
2	New York Independent System Operator	Gregory Campoli	Affirmative	View
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Affirmative	View
3	Alabama Power Company	Richard J. Mandes	Negative	View
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Negative	View
3	Arkansas Electric Cooperative Corporation	Philip Huff	Abstain	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	Avista Corp.	Robert Lafferty	Affirmative	View
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	View
3	Black Hills Power	Andy Butcher	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	View
3	City of Leesburg	Phil Janik	Affirmative	
3	Cleco Corporation	Michelle A Corley	Abstain	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	View
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	Entergy	Joel T Plessinger	Abstain	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Negative	View
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Negative	
3	Hydro One Networks, Inc.	David L Kiguel	Affirmative	View
3	JEA	Garry Baker	Affirmative	

3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Negative	View
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	View
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	PacifiCorp	John Apperson	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey	Affirmative	View
3	Tennessee Valley Authority	Ian S Grant	Negative	View
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power - Ohio	Kevin Koloini	Abstain	
4	American Public Power Association	Allen Mosher	Affirmative	
4	Arkansas Electric Cooperative Corporation	Ronnie Frizzell	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Abstain	
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Negative	
4	LaGen	Richard Comeaux		
4	Modesto Irrigation District	Spencer Tacke	Negative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Oklahoma Municipal Power Authority	Terri Pyle	Abstain	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Tallahassee Electric	Allan Morales	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5		Edwin B Cano	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	APS	Mel Jensen	Negative	View
5	Avista Corp.	Edward F. Groce	Abstain	
5	BC Hydro and Power Authority	Clement Ma		

5	Black Hills Corp	George Tatar	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Alan Gale	Affirmative	
5	Cleco Power	Stephanie Huffman	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	View
5	Consumers Energy	James B Lewis	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Electric Power Supply Association	Jack Cashin		
5	Energy Northwest - Columbia Generating Station	Doug Ramey	Affirmative	
5	Entergy Corporation	Stanley M Jaskot		
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	JEA	Donald Gilbert	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	Thomas J Trickey		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	View
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	View
5	New York Power Authority	Gerald Mannarino		
5	Northern California Power Agency	Tracy R Bibb	Abstain	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Pete Ungerman	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	Jerzy A Slusarz	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	View
5	Tampa Electric Co.	RJames Rocha	Affirmative	View
5	Tenaska, Inc.	Scott M. Helyer	Negative	
5	Tennessee Valley Authority	George T. Ballew	Negative	View
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Abstain	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	View
6	Arizona Public Service Co.	Justin Thompson	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	View
6	City of Austin dba Austin Energy	Lisa L Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak	Abstain	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit		
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View

6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	View
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8		Roger C Zaklukiewicz		
8		James A Maenner	Affirmative	
8		Edward C Stein	Affirmative	
8	INTELLIBIND	Kevin Conway		
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Transmission Strategies, LLC	Bernie M Pasternack	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	View
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	Oregon Public Utility Commission	Jerome Murray	Affirmative	
9	Snohomish County PUD No. 1	William Moojen	Affirmative	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	View
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool Regional Entity	Stacy Dochoda		
10	Texas Reliability Entity	Larry D Grimm	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	View

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Account Log-In/Register

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR approved by SC in May 2012.

Proposed Action Plan and Description of Current Draft:

The SDT is working to address FERC's remand of the proposed clarification of TPL-002, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System. That footnote is captured here as footnote 12.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Initial posting	July 2012
2. Recirculation ballot	October 2012
3. BOT approval	February 2013

Definitions of Terms Used in Standard

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

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-3a**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter 84 months after Board of Trustees adoption, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-3, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3) that would not otherwise be permitted by the requirements of TPL-001-3:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes

Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in-service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that time frame and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan
- Use of rate applications, DSM, new technologies, or other initiatives

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required time frame, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that

Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high-speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
      ii. Loss of the use of a large body of water as the cooling source for generation.
      iii. Wildfires.
      iv. Severe weather, e.g., hurricanes, tornadoes, etc.
      v. A successful cyber attack.
      vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
   b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   e. 3Ø internal breaker fault.
   f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to ensure that BES performance requirements are met. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 12 exceed 'x' MW.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity shall document the stakeholder process which shall include the following:

1. Meetings must be open to all affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues.
2. Notice must be provided in advance of meetings to all affected stakeholders, including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific applications of the planned Firm Demand interruption under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote 12 (as shown in Section II below) must be made available to meeting participants.
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns.
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote 12 which must include the following:

1. Conditions under which Firm Demand interruption under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Firm Demand MW to be interrupted with:
    a. The estimated number and type of customers affected
    b. An assessment of the use of Firm Demand interruption under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Firm Demand interruption under footnote 12 based on historical performance.

4. Expected duration of Firm Demand interruption under footnote 12 based on historical performance.
5. Future plans to mitigate the need for Firm Demand interruption under footnote 12.
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12.
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote 12.
8. Assessment of potential overlapping uses of footnote 12 with adjacent planners.

III. Instances for which Approval of Interruptions of Firm Demand under footnote 12 is Required

Approval of the use of Firm Demand interruption under footnote 12 by the applicable regulatory authority or governing body responsible for retail electric service issues is required if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote 12
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote 12 is greater than or equal to 25 MW.

Before a Firm Demand interruption under footnote 12 is allowed to be utilized as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that approval is obtained from the regulatory authority or governing body responsible for retail electric service issues. In no case can the planned Firm Demand interruption under footnote 12 exceed x MW.

When approval for the use of a footnote 12 Firm Demand interruption is necessary under items III.1 or III.2 above, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the Regional Entity. Within 45 days of receipt of this information, the Regional Entity must review each proposed use of Firm Demand interruption under footnote 12 to verify that there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity's footprint. If the Regional Entity states that an Adverse Reliability Impact will result due to the requested Firm Demand interruption, then the requesting entity may appeal the decision to the ERO. Regional Entity determinations of Adverse Reliability Impacts are to be evaluated by the Regional Entity through a published methodology approved by the ERO.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Time frame

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in-force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	03/17/2001	Revision of TPL-001-0 to modify only Table 1 footnote b. Approved by Board of Trustees	Project 2006-02 – revision to address FERC directive
2	To be Determined	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-3; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2a	February 2013	Address remand of proposed Attachment 1 pursuant to FERC Order RM06-16-009	Revised

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR approved by SC in May 2012.

Proposed Action Plan and Description of Current Draft:

The SDT is working to address FERC's remand of the proposed clarification of TPL-002, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System. That footnote is captured here as footnote 12.

Future Development Plan:

Anticipated Actions	**Anticipated Date**
1. Initial posting	July 2012
2. Recirculation ballot	October 2012
3. BOT approval	February 2013

Definitions of Terms Used in Standard

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

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

A. Introduction

1. Title: Transmission System Planning Performance Requirements

2. Number: TPL-001-~~2~~3a

3. Purpose: Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. Applicability:

4.1. Functional Entity

4.1.1. Planning Coordinator.

4.1.2. Transmission Planner.

5. Effective Date: Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter 84 months after Board of Trustees adoption, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-~~2~~3, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3~~.)~~)) that would not otherwise be permitted by the requirements of TPL-001-~~2~~3:

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes

Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in~~-~~-service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that ~~timeframe~~time frame and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment~~.~~
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations~~.~~
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations~~.~~
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan~~.~~
- Use of rate applications, DSM, new technologies, or other initiatives~~.~~

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required ~~timeframe~~time frame, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. ~~–~~The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that

Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high~~-~~-speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: ~~Lower~~Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: ~~Lower~~Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events	
Steady State & Stability For all extreme events evaluated: a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency. b. Simulate Normal Clearing unless otherwise specified.	
Steady State 1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments. 2. Local area events affecting the Transmission System such as: a. Loss of a tower line with three or more circuits.[11] b. Loss of all Transmission lines on a common Right-of-Way[11]. c. Loss of a switching station or substation (loss of one voltage level plus transformers). d. Loss of all generating units at a generating station. e. Loss of a large Load or major Load center. 3. Wide area events affecting the Transmission System based on System topology such as: a. Loss of two generating stations resulting from conditions such as: i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation. ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances.	**Stability** 1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments. 2. Local or wide area events affecting the Transmission System such as: a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing. e. 3Ø internal breaker fault. f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to ~~address~~ensure that BES performance requirements are met. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is ~~documented, including alternatives evaluated; and where the utilization of Non-Consequential Load Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments~~meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 12 exceed 'x' MW.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity shall document the stakeholder process which shall include the following:

1. Meetings must be open to all affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues.
2. Notice must be provided in advance of meetings to all affected stakeholders, including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
   a. Date, time, and location for the meeting
   b. Specific applications of the planned Firm Demand interruption under footnote 12
   c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote 12 (as shown in Section II below) must be made available to meeting participants.
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns.
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote 12 which must include the following:

1. Conditions under which Firm Demand interruption under footnote 12 would be necessary:
   a. System Load level and estimated annual hours of exposure at or above that Load level
   b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Firm Demand MW to be interrupted with:
   a. The estimated number and type of customers affected
   b. An assessment of the use of Firm Demand interruption under footnote 12 on the health, safety, and welfare of the community

3. Estimated frequency of Firm Demand interruption under footnote 12 based on historical performance.
4. Expected duration of Firm Demand interruption under footnote 12 based on historical performance.
5. Future plans to mitigate the need for Firm Demand interruption under footnote 12.
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12.
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote 12.
8. Assessment of potential overlapping uses of footnote 12 with adjacent planners.

III. Instances for which Approval of Interruptions of Firm Demand under footnote 12 is Required

Approval of the use of Firm Demand interruption under footnote 12 by the applicable regulatory authority or governing body responsible for retail electric service issues is required if either:

1. The voltage level of the Contingency is greater than 300 kV
    a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote 12
    b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote 12 is greater than or equal to 25 MW.

Before a Firm Demand interruption under footnote 12 is allowed to be utilized as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that approval is obtained from the regulatory authority or governing body responsible for retail electric service issues. In no case can the planned Firm Demand interruption under footnote 12 exceed x MW.

When approval for the use of a footnote 12 Firm Demand interruption is necessary under items III.1 or III.2 above, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the Regional Entity. Within 45 days of receipt of this information, the Regional Entity must review each proposed use of Firm Demand interruption under footnote 12 to verify that there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity's footprint. If the Regional Entity states that an Adverse Reliability Impact will result due to the requested Firm Demand interruption, then the requesting entity may appeal the decision to the ERO. Regional Entity determinations of Adverse Reliability Impacts are to be evaluated by the Regional Entity through a published methodology approved by the ERO.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and ~~-~~Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset ~~Timeframe~~Time frame

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in-~~-~~force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
~~0~~	~~April 1, 2005~~	~~Effective Date~~	~~New~~
~~0~~	~~February 8, 2005~~	~~BOT Approval~~	~~Revised~~
~~0~~	~~June 3, 2005~~	~~Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2~~	~~Errata~~
~~0~~	~~July 24, 2007~~	~~Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.~~	~~Errata~~
~~0.1~~	~~October 29, 2008~~	~~BOT adopted errata changes; updated version number to "0.1"~~	~~Errata~~
~~0.1~~	~~May 13, 2009~~	~~FERC Approved – Updated Effective Date and Footer~~	~~Revised~~
1	~~Approved by Board of Trustees February 17, 2011~~03/17/2001	Revision of TPL-001-0 to modify only Table 1 footnote b. Approved by Board of Trustees~~Revised footnote 'b' pursuant to FERC Order RM06-16-009~~	~~Revised (~~Project ~~2010-11)~~2006-02 – revision to address FERC directive
2	~~August 4, 2011~~To be Determined	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-~~2~~3; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
~~2~~2a	~~August 4, 2011~~February 2013	~~Adopted by Board of Trustees~~Address remand of proposed Attachment 1 pursuant to FERC Order RM06-16-009	Revised

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR approved by SC in May 2012.

Proposed Action Plan and Description of Current Draft:

The SDT is working to address FERC's remand of the proposed clarification of TPL-002, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System. Table 1 appears in the first four of the current TPL standards but footnote 'b' only applies to TPL-002. Therefore, only TPL-002 is being posted for industry comment at this time. When the footnote has been approved, all four of the applicable TPL standards will be filed with the Commission.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Initial posting	July 2012
2. Recirculation ballot	October 2012
3. BOT approval	February 2013

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-1c

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1, Requirement R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1, Requirement R1 and TPL-002-1, Requirement R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1, Requirement R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised
1c	February 2013	Address remand of proposed footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to ensure that BES performance requirements are met. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 'x' MW.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 'b' is reviewed through an open and transparent stakeholder process. The responsible entity shall document the stakeholder process which shall include the following:

1. Meetings must be open to all affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to all affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific applications of the planned Firm Demand interruption under footnote 'b'
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote 'b' (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote 'b' which must include the following:

1. Conditions under which Firm Demand interruption under footnote 'b' would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Firm Demand MW to be interrupted with:
    a. The estimated number and type of customers affected
    b. An assessment of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community

3. Estimated frequency of Firm Demand interruption under footnote ‘b’ based on historical performance
4. Expected duration of Firm Demand interruption under footnote ‘b’ based on historical performance
5. Future plans to mitigate the need for Firm Demand interruption under footnote ‘b’
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote ‘b’
8. Assessment of potential overlapping uses of footnote ‘b’ with adjacent planners

III. Instances for which Approval of Interruptions of Firm Demand under Footnote ‘b’ is Required

Approval of the use of Firm Demand interruption under footnote ‘b’ by the applicable regulatory authority or governing body responsible for retail electric service issues is required if either:

1. The voltage level of the Contingency is greater than 300 kV
    a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote ‘b’
    b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote ‘b’ is greater than or equal to 25 MW.

Before a Firm Demand interruption under footnote ‘b’ is allowed to be utilized as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that approval is obtained from the regulatory authority or governing body responsible for retail electric service issues. In no case can the planned Firm Demand interruption under footnote ‘b’ exceed x MW.

When approval for the use of a footnote ‘b’ Firm Demand interruption is necessary under items III.1 or III.2 above, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the Regional Entity. Within 45 days of receipt of this information, the Regional Entity must review each proposed use of Firm Demand interruption under footnote ‘b’ to verify that there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity’s footprint. If the Regional Entity states that an Adverse Reliability Impact will result due to the requested Firm Demand interruption, then the requesting entity may appeal the decision to the ERO. Regional Entity determinations of Adverse Reliability Impacts are to be evaluated by the Regional Entity through a published methodology approved by the ERO.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR approved by SC in May 2012.

Proposed Action Plan and Description of Current Draft:

The SDT is working to address FERC's remand of the proposed clarification of TPL-002, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System. Table 1 appears in the first four of the current TPL standards but footnote 'b' only applies to TPL-002. Therefore, only TPL-002 is being posted for industry comment at this time. When the footnote has been approved, all four of the applicable TPL standards will be filed with the Commission.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Initial posting	July 2012
2. Recirculation ballot	October 2012
3. BOT approval	February 2013

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-~~0b~~1cb

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

~~**5. Effective Date:** Immediately after approval of applicable regulatory authorities.~~

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories~~,~~, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-~~0~~ 1, Requirement R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-~~0~~ 1, Requirement R1 and TPL-002-~~0~~ 1, Requirement R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-~~0~~ 1, Requirement R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
~~0~~	~~February 8, 2005~~	~~Adopted by NERC Board of Trustees~~	~~New~~
0	April 1, 2005	Effective Date	New
0a	~~July 30~~October 23, 2008	~~Adopted by NERC Board of Trustees~~Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	~~New~~Revised
~~0a~~0b	~~October 23, 2008~~November 5, 2009	Added Appendix ~~1~~2 – Interpretation of ~~TPL-002-0 Requirements~~ R1.3.~~2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO~~ 10 approved by BOT on November 5, 2009	~~Revised~~Addition
~~0b~~1b	~~November 5,~~	~~Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5,~~	~~Interpretation~~Revised

	~~2009~~April 2010	~~2009~~Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	
~~0b~~1c	~~September 15, 2011~~February 2013	~~FERC Order issued approving the Interpretation of R1.3.10 (FERC Order becomes effective October 24, 2011)~~Address remand of proposed footnote ‘b’ pursuant to FERC Order RM06-16-009	~~Interpretation~~Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - - - - - - - - - - - - - - - - 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

~~b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.~~

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to ensure that BES performance requirements are met. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 'x' MW.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 'b' is reviewed through an open and transparent stakeholder process. The responsible entity shall document the stakeholder process which shall include the following:

1. Meetings must be open to all affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to all affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific applications of the planned Firm Demand interruption under footnote 'b'
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote 'b' (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote 'b' which must include the following:

1. Conditions under which Firm Demand interruption under footnote 'b' would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Firm Demand MW to be interrupted with:
    a. The estimated number and type of customers affected
    b. An assessment of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community

3. Estimated frequency of Firm Demand interruption under footnote ‘b’ based on historical performance
4. Expected duration of Firm Demand interruption under footnote ‘b’ based on historical performance
5. Future plans to mitigate the need for Firm Demand interruption under footnote ‘b’
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote ‘b’
8. Assessment of potential overlapping uses of footnote ‘b’ with adjacent planners

III. Instances for which Approval of Interruptions of Firm Demand under Footnote ‘b’ is Required

Approval of the use of Firm Demand interruption under footnote ‘b’ by the applicable regulatory authority or governing body responsible for retail electric service issues is required if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote ‘b’
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote ‘b’ is greater than or equal to 25 MW.

Before a Firm Demand interruption under footnote ‘b’ is allowed to be utilized as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that approval is obtained from the regulatory authority or governing body responsible for retail electric service issues. In no case can the planned Firm Demand interruption under footnote ‘b’ exceed x MW.

When approval for the use of a footnote ‘b’ Firm Demand interruption is necessary under items III.1 or III.2 above, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the Regional Entity. Within 45 days of receipt of this information, the Regional Entity must review each proposed use of Firm Demand interruption under footnote ‘b’ to verify that there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity’s footprint. If the Regional Entity states that an Adverse Reliability Impact will result due to the requested Firm Demand interruption, then the requesting entity may appeal the decision to the ERO. Regional Entity determinations of Adverse Reliability Impacts are to be evaluated by the Regional Entity through a published methodology approved by the ERO.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

> **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.

Background Information for Interpretation

Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations:

1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)."
2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)."
3. "Include the effects of existing and planned protection systems, including any backup or redundant systems."

Category B of Table 1 (single Contingencies) specifies:

Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:

1. Generator
2. Transmission Circuit
3. Transformer

Loss of an Element without a Fault.

Single Pole Block, Normal Clearing[e]:

4. Single Pole (dc) Line

Note e specifies:

e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."

Conclusion

TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.

This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

Project 2010-11

Revision of TPL-002 footnote ‘b’ and TPL-001 footnote 12

Unofficial Comment Form

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by **August 29, 2012**.

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

The project web page is located here:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Background Information

This posting is soliciting formal comment.

FERC Order No. 762 issued April 19, 2012 remanded TPL-002-0b as vague, unenforceable and not responsive to the previous Commission directives on this matter. The Standards Committee directed the Standards Drafting Team (SDT) to revise footnote ‘b’ in accordance with the directives of Orders No. 693 and 762. The SDT was also charged with revising the corresponding footnote 12 of TPL-001-2 in order to prevent the remand of TPL-001-2.

The SDT adopted a philosophy of minimal changes to the actual footnote itself. This was done to minimize confusion as to what was changed, for ease of reading and following the footnote, and for formatting within the actual standards documents. This philosophy resulted in the development of an attachment to the footnote where the actual changes in response to the Commission Orders are contained. It should be noted that attachments to standards are part and parcel of the standard itself and thus are binding to applicable entities.

A draft data request to collect data to assist the SDT in its work was posted for an abbreviated comment period in accordance with Section 1600 of the NERC Rules of Procedure, through July 9, 2012. The draft data request will be revised as appropriate to reflect industry comments and then issued for formal response. The timing of the formal data request response will allow for the data to be evaluated by the SDT in the same timeframe as the responses to this posting.

The SDT has proposed three thresholds within the proposed footnote revision in Section III of Attachment 1 in order to address the Order.

- The last sentence in the body of the footnote is to allow for the placement of a maximum capacity limit to the amount of Firm Demand that be be dropped under footnote 'b'. The value is currently shown as 'x' MW. The SDT will fill in the value after the above mentioned data request is complete and will submit the value for industry comment and approval in the next posting. However, industry comments on the proposed maximum capacity issue can be submitted now in response to question 1.
- The 300 kV threshold in Section III is derived from the EHV value approved by the industry through the Standards Development Process, approved by the NERC Board of Trustees, and favorably received by the Commission in the TPL-001-2 filing.
- The 25 MW threshold in Section III is duplicative of the registration limit for generation in the ERO Statement of Compliance Registry Criteria. It is submitted for comment at this time but will not be finalized until after the above mentioned data request is complete and the final value will be submitted for industry comment and approval in the next posting.

There have been no changes to the Implementation Plan originally filed with the standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format. Bullets, numbers, and special formatting will not be retained.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree with the description and components of the the Stakeholder Process in the body of the footnote including the maximum capacity threshold (currently shown as 'x' MW but the SDT will fill in the value after the data request is complete and will submit the value for industry comment and approval in the next posting)? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. For the maximum capacity item, please supply any technical rationale for your comment along with limiting conditions and any current criteria in use at your entity.

☐ Yes

☐ No

Comments:

2. Do you agree with the description and components of the the Stakeholder Process in Section I of Attachment I? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes

☐ No

Comments:

3. Do you agree with the Information for Inclusion in the Stakeholder Process contained in Section II of Attachment I? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes

☐ No

Comments:

4. Do you agree with the Instances for which Approval of Interruptions is required in Section III of Attachment I? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes

☐ No

Comments:

5. If you have any other comments on this Standard that you haven't already mentioned above, please provide them here:

Comments:

Standard Authorization Request Form

Request Date	Revision of TPL-002 footnote ‘b’ and TPL-001 footnote 12

SAR Requester Information	**SAR Type** (*Check a box for each one that applies.*)	
Individual, Group, or Committee Name Standards Committee	☐	New Standard
Primary Contact (if Group or Committee) Allen Mosher	X	Revision to existing Standard
Company or Group Name APPA	☐	Withdrawal of existing Standard
E-mail amosher@publicpower.org	☐	Project Identified in Reliability Standards Development Plan (Project Number and Name:)
Telephone (202) 467-2944	☐	Modification to NERC Glossary term or addition of new term

Brief Description of Proposed Standard Modifications/Actions
The drafting team must provide clarity on TPL-002-0, Table 1 - footnote 'b' and TPL-001-2 Table 1 footnote 12, regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. The drafting team must quickly respond to the directives in Order No. 762 ~~in order to preserve their ability to~~to address planned ~~to~~ load shed ~~load~~ under limited circumstances for certain contingencies.
Need On April 19, 2012, FERC issued Order No. 762 remanding TPL-002-2b because FERC determined that footnote b to Table 1 of that Reliability Standard was vague, unenforceable, and not responsive to previous directives. Therefore FERC found TPL-002-2b to be unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. In a related matter, FERC proposed to remand TPL-001-2 because NERC incorporated footnote b into the new TPL-001-2 reliability standard. NERC has been directed to revise footnote b in accordance with the directives of Order Nos. 762 and 693. This project will also revise footnote 12 to TPL-001-2 in order to prevent the remand of TPL-001-2. This provision will allow for entities to plan to shed load under very limited circumstances so long as there is no adverse reliability impact to the BES.
Goals (Describe what must be accomplished in order to meet the above need. This section would become the Requirements in a Reliability Standard.) NERC must develop a process that will not adversely impact BES reliability and that satisfies the directives of Order No. 762 by clearly delineating when entities may plan for load shedding following a single contingency.
Objectives and/or Potential Future Metrics The drafting team must ~~either~~ develop a ~~blend of quantitative and qualitative methodologies or a specific "customer consent"~~ process that will allow for planning to shed load following a single contingency. The drafting team must consider the guidance provided by the Commission in Order 762, including but not limited to: • Form OE-417 or the Registry Criteria are not, by themselves, beneficial to use to devise criteria (see paragraph 49 of Order 762). ~~.~~ • Setting a quantitative and qualitative threshold in developing a limited exception for planned interruption of Firm Demand may be a workable solution (see paragraph 54 of Order 762). • A customer should have notice and understanding that the transmission planner plans to curtail certain Firm Demand in the event of a single contingency indentified in the system modeling under NERC's Transmission Planning requirements (see paragraph 65 of Order 762). • If there is a threshold component to the revised footnote, the rational for the threshold should be supported and show that instability, uncontrolled separation, or cascading failures of the system will not occur as a result of planning to shed Firm Demand up to the threshold (see paragraph 67 of Order 762). • If there is an individual exception option, the applicable entities should be required to find that there is no adverse impact to the Bulk-Power System from the exception and that it is considered in wide-area coordination and operations (see paragraph 67 of Order 762). • Any exception should be subject to further review by the Regional Entity or NERC (see paragraph 67 of Order 762).
Detailed Description The drafting team must provide clarity on TPL-002-0, Table 1 -

footnote 'b' and TPL-001-2 Table 1 footnote 12, regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. The drafting team must quickly respond to the directives in Order No. 762 ~~in order to~~ to address planned load shed under ~~preserve their ability to plan to shed load under~~ limited circumstances for certain contingencies. NERC has been directed to revise footnote b in accordance with the directives of Order Nos. 762 and 693. This project will also revise footnote 12 to TPL-001-2 in order to prevent the remand of TPL-001-2. This provision will allow for entities to plan to shed load under very limited circumstances so long as there is no adverse reliability impact to the BES.
~~OPTIONAL:~~ Technical Analysis Performed to Support Justification NERC will be conducting a mandatory Data Request to identify the specific instances of any planned interruptions of Firm Demand under footnote 'b' and how frequently the provision has been used in parallel with this SAR. The drafting team should evaluate and consider the results of the data request in conjunction with drafting the revised Footnote b.

Reliability Functions

The Standard(s) May Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Regional Entity	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
X	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
X	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission	Owns and maintains transmission facilities.

	Owner	
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
X	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard(s) comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
TPL-001-0.1	System Performance Under Normal (No Contingency) Conditions (Category A)
TPL-002-0b	System Performance Following Loss of a Single Bulk Electric System Element (Category B)
TPL-003-0a	System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
TPL-004-0	System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

Related Projects

Project ID and Title	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

139 FERC ¶ 61,060
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM11-18-000; Order No. 762]

Transmission Planning Reliability Standards

(Issued April 19, 2012)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: Under section 215 of the Federal Power Act, the Federal Energy Regulatory Commission remands proposed Transmission Planning (TPL) Reliability Standard TPL-002-0b, submitted by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. The proposed Reliability Standard includes a provision that allows for planned load shed in a single contingency provided that the plan is documented and alternatives are considered and vetted in an open and transparent process. The Commission finds that this provision is vague, unenforceable and not responsive to the previous Commission directives on this matter. Accordingly, the Final Rule remands NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest.

DATES: This rule will become effective **[Insert date 60 days after publication in the FEDERAL REGISTER].**

ADDRESSES: You may submit comments, identified by docket number by any of the following methods:

- Agency Web Site: http://www.ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Commenters unable to file comments electronically must mail or hand deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

FOR FURTHER INFORMATION CONTACT:

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Federal Energy Regulatory Commission
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Washington, DC 20426
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SUPPLEMENTARY INFORMATION:

139 FERC ¶ 61,060
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

Transmission Planning Reliability Standards Docket No. RM11-18-000

Order No. 762

FINAL RULE

(Issued April 19, 2012)

1. Under section 215(d) of the Federal Power Act,[1] the Commission remands proposed Transmission Planning (TPL) Reliability Standard TPL-002-0b, submitted by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. The proposed Reliability Standard includes a provision that allows for planned load shed in a single contingency provided that the plan is documented and alternatives are considered and vetted in an open and transparent process.[2] The Commission finds that this provision is vague, unenforceable and not responsive to the previous Commission directives on this matter. Accordingly, the Final

[1] 16 U.S.C. § 824o(d)(4) (2006).

[2] NERC filed a petition seeking approval of Table 1, footnote 'b' of four Reliability Standards: Transmission Planning: TPL-001-1– System Performance Under Normal (No Contingency) Conditions (Category A), TPL-002-1b – System Performance Following Loss of a Single Bulk Electric System Element (Category B), TPL-003-1a – System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), and TPL-004-1– System Performance Following Extreme Events Resulting

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Rule remands NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. We require NERC to utilize its Expedited Reliability Standards Development Process to develop timely modifications to TPL-002-0b, Table 1 footnote 'b' in response to our remand.[3]

I. Background

2. Section 215 of the FPA requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Approved Reliability Standards are enforced by the ERO, subject to Commission oversight, or by the Commission independently. On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including Reliability Standard TPL-002-0.[4] In addition, pursuant to section 215(d)(5) of the FPA,[5] the Commission directed

in the Loss of Two or More Bulk Electric System Elements (Category D). While footnote 'b' appears in all four of the above referenced TPL Reliability Standards, its relevance and practical applicability is limited to TPL-002-0a.

[3] NERC Rules of Procedure, Appendix 3A, Standard Processes Manual at 34 (effective January 31, 2012).

[4] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[5] 16 U.S.C. § 824o(d)(5)(2006).

NERC to develop modifications to 56 of the 83 approved Reliability Standards, including footnote ‘b’ of Reliability Standard TPL-002-0.[6]

A. Transmission Planning (TPL) Reliability Standards

3. Currently-effective Reliability Standard TPL-002-0b addresses Bulk-Power System planning and related transmission system performance for single element contingency conditions. Requirement R1 of TPL-002-0b requires that each planning authority and transmission planner “demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the network can be operated to supply projected customer demands and projected firm transmission services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I.”[7] Table I identifies different categories of contingencies and allowable system impacts in the planning process. With regard to system impacts, Table I further provides that a Category B (single) contingency must not result in cascading outages, loss of demand or curtailed firm transfers, system instability or exceeded voltage or thermal limits. With regard to loss of demand, current footnote ‘b’ of Table 1 states:

> Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems.

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[6] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1797.

[7] Reliability Standard TPL-002-0a, Requirement R1.

> To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

B. Order No. 693 Directive

4. In Order No. 693, the Commission stated that it believes that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential firm load in the event of a single contingency.[8] The Commission directed the ERO to develop certain modifications, including a clarification of Table 1, footnote 'b.'

5. In a subsequent clarifying order, the Commission stated that it believed that a regional difference, or a case-specific exception process that can be technically justified, to plan for the loss of firm service would be acceptable in limited circumstances.[9] Specifically, the Commission stated that "a regional difference, or a case-specific exception process that can be technically justified, to plan for the loss of firm service at the fringes of various systems would be an acceptable approach."[10]

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[8] *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1794.

[9] *Mandatory Reliability Standards for the Bulk Power System*, 131 FERC ¶ 61,231, at P 21 (2010) (June 2010 Order).

[10] *Id.*

C. NERC Petition

6. On March 31, 2011, NERC filed a petition seeking approval of its proposal to revise and clarify footnote 'b' "in regard to load loss following a single contingency."[11] NERC stated that it did not eliminate the ability of an entity to plan for the loss of non-consequential load in the event of a single contingency but drafted a footnote that, according to NERC, "meets the Commission's directive while simultaneously meeting the needs of industry and respecting jurisdictional bounds."[12] NERC stated that its proposed footnote 'b' establishes the requirements for the limited circumstances when and how an entity can plan to interrupt Firm Demand for Category B contingencies. According to NERC, the provision allows for planned interruption of Firm Demand when "subject to review in an open and transparent stakeholder process."[13] NERC's proposed footnote 'b' states:

> An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate redispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements.

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[11] NERC Petition at 10.

[12] *Id.*

[13] *Id.*

> When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

7. NERC supplemented the filing on June 7, 2011, in response to a Commission deficiency letter. NERC explained that "the approach proposed in footnote 'b' is equally efficient because many of the stakeholder processes that will be used in footnote 'b' planning decisions are already in place, as implemented by FERC in Order No. 890 and in state regulatory jurisdictions."[14] NERC also pointed to state public utility commission processes or processes existing in local jurisdictions that address transmission planning issues that could serve to provide a case-specific review of the planned interruption of Firm Demand. According to NERC, such processes would more likely engage the appropriate local-level decision-makers and policy-makers.

8. With respect to review and oversight by NERC and the Regional Entities, NERC submitted that an ERO-specific process would place the ERO in the position of managing and actively participating in a planning process, which conflicts with its role as the compliance monitor and enforcement authority. NERC also stated that neither the ERO nor the Regional Entities will review decisions regarding planned interruptions. Their role will be limited to reviewing whether the registered entity participated in a stakeholder process when planning to interrupt Firm Demand. NERC explained that

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[14] NERC Data Response at 4.

Regional Entities will have oversight after-the-fact by auditing the entity's implementation of footnote 'b' to determine if the entity planned on interrupting Firm Demand and whether the decision by the entity to rely on planned interruption of Firm Demand was vetted through the stakeholder process and qualified as one of the situations identified in footnote 'b.'

9. Furthermore, NERC stated that an objective of the planning process should be to minimize the likelihood and magnitude of planned Firm Demand interruptions. NERC contended that, due to the wide variety of system configurations and regulatory compacts, it is not feasible for the ERO to develop a one-size-fits-all criterion for limiting the planned firm load interruptions for Category B events. According to NERC, the standards drafting team evaluated setting a certain magnitude of planned interruption of Firm Demand, but there was no analytical data to support a single value, and it would be viewed as arbitrary.

D. <u>Notice of Proposed Rulemaking</u>

10. On October 20, 2011, the Commission issued a Notice of Proposed Rulemaking (NOPR[15]) proposing to remand NERC's proposal to modify footnote 'b.' In the NOPR, the Commission stated that it believed that NERC's proposal does not meet the directives in Order No. 693 and the June 2010 Order and does not clarify or define the circumstances in which an entity can plan to interrupt Firm Demand for a single

[15] *Transmission Planning Reliability Standards*, Notice of Proposed Rulemaking, 76 FR 66229 (Oct. 20, 2011), FERC Stats. & Regs. ¶ 32,683 (2011).

contingency. The Commission expressed concern that the procedural and substantive parameters of NERC's proposed stakeholder process are too undefined to provide assurances that the process will be effective in determining when it is appropriate to plan for interrupting Firm Demand, does not contain NERC-defined criteria on circumstances to determine when an exception for planned interruption of Firm Demand is permissible, and could result in inconsistent results in implementation. The NOPR stated that the proposed footnote effectively turns the processes into a reliability standards development process outside of NERC's existing procedures. Furthermore, the NOPR stated that regardless of the process used, the result could lead to inconsistent reliability requirements within and across reliability regions. While the Commission recognized that some variation among regions or entities is reasonable, there are no technical or other criteria to determine whether varied results are arbitrary or based on meaningful distinctions.

11. The Commission proposed to provide further guidance on acceptable approaches to footnote 'b' and sought comment on certain options for revising footnote 'b', as well as other potential options to solve the concerns outlined in the NOPR. In response to the NOPR, comments were filed by seventeen interested parties.[16]

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[16] NERC, The Edison Electric Institute (EEI), American Public Power Association (APPA), National Association of Regulatory Utility Commissioners (NARUC), ITC Holdings Corp. (ITC), Manitoba Hydro, California Department of Water Resources State Water Project (California SWP) Hydro One Networks, Inc and the Ontario Independent Electricity System Operator (Hydro One and IESO), Duke Energy Corporation (Duke), New York State Public Service Commission (NYPSC), Bonneville Power Administration

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II. Discussion

12. For the reasons discussed below, the Commission concludes that NERC's proposed TPL-002-0b does not meet the Commission's Order No. 693 directives, nor is it an equally effective and efficient alternative. Further, the Commission finds that the proposal is vague, potentially unenforceable and may lack safeguards to produce consistent results. On this basis, the Commission remands the proposal to NERC as unjust, unreasonable, unduly discriminatory or preferential and not in the public interest. Below, the Commission also provides guidance on acceptable approaches to footnote 'b.'

13. The Commission adopts the proposed NOPR finding that the footnote 'b' process lacks adequate parameters. The Reliability Standard requires that, when planning to interrupt Firm Demand, the Firm Demand interruption must be "subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments."[17] Without meaningful substantive parameters governing the stakeholder process, the enforceability of this obligation by NERC and the Regional Entities would be limited to a review to ensure only that a stakeholder process occurred. As NERC explained, Regional Entities' involvement is limited to after-the-fact oversight by

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(BPA), Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company (KCPL), Midwest Independent System Operator, Inc. (MISO), Public Utility District No. 1 of Snohomish County, Washington, (Snohomish), Transmission Access Policy Study Group (TAPS), Powerex Corp. (Powerex), and Florida Reliability Coordinating Council (FRCC).

[17] NERC Petition at 10.

auditing the entity's implementation of footnote 'b' to determine if the entity planned on interrupting Firm Demand and whether the decision by the entity to rely on planned interruption of Firm Demand was vetted through the stakeholder process and qualified as one of the situations identified in footnote 'b.'[18]

14. Further, the NERC proposal leaves undefined the circumstances in which it is allowable to plan for Firm Demand to be interrupted in response to a Category B contingency. The Commission believes that proposed footnote 'b' could be used as a means to override the reliability objective and system performance requirements of the TPL Reliability Standard without any technical or other criteria specified to determine when planning to interrupt Firm Demand would be allowable, and without violating any of the requirements of the TPL Reliability Standard. The TPL Reliability Standard requires that a planner demonstrate through a valid assessment that the transmission system is planned and can be operated to supply projected Firm Demand at all demand levels over a range of forecasted system demands.[19] In addition, a planner must consider all single contingencies under Table 1, Category B and demonstrate system performance.[20] For single contingency events where system performance is not met, a planner must provide a written summary of its plans to achieve system performance

[18] NERC Data Response at 7-9.

[19] Reliability Standard TPL-002-0b, Requirement R1.

[20] Reliability Standard TPL-002-0b, Requirement R1.3.7.

including implementation schedules, in service dates of facilities and implementation lead times.[21]

15. However, if system performance is not met for any single contingency event(s) under NERC's proposed footnote 'b,' a planner could plan to interrupt some portion of Firm Demand to meet system performance requirements thereby overriding the performance requirements of the TPL Reliability Standard. For example, if a planner determines during its annual assessment that for a single bulk-power system transformer contingency other bulk-power system elements would exceed their thermal ratings, a planner would have authority under the standard to plan to interrupt Firm Demand to relieve the exceeded thermal ratings of the bulk-power system elements rather than planning the system to withstand such a single contingency and avoid shedding firm load as the performance requirements of the TPL Reliability Standard require. Therefore, without articulating some bounds on the use of the planned shedding of Firm Demand, there could be instances of multiple exceptions that could affect the robustness of the system. Further, contrary to commenters contentions, NERC's proposal, for example, has no provision to evaluate this cumulative effect of the individual decisions to shed firm.[22]

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[21] Reliability Standard TPL-002-0b, Requirement R2.

[22] BPA Comments at 5 ("The reasons for interrupting Firm Demand would be documented in studies and demonstrate that there would be no adverse impact to the BPS"); FRCC Comments at 3 ("Indeed, the transmission planning entity is responsible as part of the system assessment process under the TPL standards to test remedies to ensure

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16. The Commission disagrees with commenters that NERC's proposed footnote 'b' will have no adverse impact on reliable planning of the bulk-power system because planning to shed Firm Demand is intended to ensure that single contingency events do not result in adverse impacts and intended to preserve bulk-power system reliability.[23] Table 1 of the TPL Reliability Standard identifies the system performance requirements or "System Limits or Impacts" that a planner must apply during its assessment of Category B, single contingency events.[24] Except in limited circumstances, if a planner determines that it must plan to interrupt Firm Demand so that it does not violate the Table 1 system performance requirements, a planner should not apply footnote 'b' as a mitigation plan to plan to operate reliably. The Commission therefore is concerned that NERC's proposal provides authority to adjust the TPL Reliability Standard and its system

that they address the problems being caused and do not cause additional problems."); and Hydro One Comments at 5 ("Loss of load is under the purview of the regulatory authority and not NERC, unless it has an adverse impact on the BES which is already taken into consideration by the TPL standards… In all cases, steps are taken in planning, design and operations of the system to ensure that Firm Demand shedding would not adversely impact the BES…").

[23] *See, e.g.,* NERC Comments at 11, TAPS Comments at 10, APPA Comments at 6.

[24] Reliability Standard TPL-002-0b, Table 1, Transmission System Standards – Normal and Emergency Conditions. Table 1 identifies the system performance requirements or "System Limits or Impacts" which are as follows: "System Stable and both Thermal and Voltage Limits within Applicable Rating", "Loss of Demand or Curtailed Firm Transfers" and "Cascading Outages."

performance requirements for each single contingency event that does not meet the system performance requirements of Table 1.

17. Further, NERC has not provided technically sound means of determining situations in which planning to interrupt Firm Demand would be allowable. While NERC expects that such determinations will be made in a stakeholder process, this provides no assurance that such a process will use technically sound means of approving or denying exceptions. The Commission concludes that the multiple stakeholder processes across the country engaging in such determinations could lead to inconsistent and arbitrary exceptions including, potentially, allowing entities to plan to interrupt any amount of Firm Demand in any location and at any voltage level.

18. While the Commission recognizes that some variation among regions or entities is reasonable given varying grid topography and other considerations, there are no technical or other criteria to determine whether varied results are arbitrary or based on meaningful distinctions. The Commission, thus, concludes that NERC's proposal lacks safeguards to ensure against inconsistent results and arbitrary determinations to allow for the planned interruption of Firm Demand.

19. A remand gives NERC and industry flexibility to develop an approach that would address the issues identified by the Commission with the proposed footnote 'b' stakeholder process including, as discussed below, definition of the process and criteria or guidelines for the process.

20. The Commission believes that, on remand, both NERC and the Commission will benefit from a more complete record regarding the electric industry's reliance on planned

Firm Demand interruptions. In response to the Commission's request to explain and quantify the extent to which Firm Demand is planned to be interrupted pursuant to currently-effective footnote 'b,' NERC explained:

> NERC and the Regional Entities have not collected statistics or preformed a survey concerning the prospective implementation of Footnote b under TPL-002-0a. During the drafting team's deliberations concerning TPL-001-2 and TPL-002-0a Footnote b, including the NERC Technical Conference on Footnote b, the informal assessments demonstrated that the use of Footnote b would not be widespread.[25]

Likewise, several commenters state that the interruption of Firm Demand is rarely needed, but provide no support for this conclusion.[26] For example, EEI asks the Commission to "recognize" that "…the actions taken as outcomes of the planning review process, are likely to identify few/isolated circumstances in which these [footnote b] provisions would be invoked…."[27] However, the Commission believes that more specific information regarding the specific circumstances and frequency with which Firm Demand is planned to be interrupted will assist both NERC in developing, and the Commission in reviewing, appropriate revisions to footnote 'b" on remand. Therefore, pursuant to section 39.2(d) of the Commission's regulations,[28] we direct NERC to identify the specific instances of any planned interruptions of Firm Demand under

[25] NERC Data Response at 10.

[26] *See, e.g.,* FRCC Comments at 4; MISO Comments at 4; BPA Comments.

[27] EEI Comments at 2.

[28] 18 U.S.C. § 39.2(d).

footnote 'b' and how frequently the provision has been used. We direct NERC to use section 1600 of its Rules of Procedure to obtain information from users, owners and operators of the bulk-power system to provide this requested data.[29] NERC shall submit this information to the Commission with NERC's footnote 'b' filing that addresses the concerns in this Final Rule.

21. We urge NERC to develop in a timely manner an appropriate modification that is responsive to the Commission's directives in Order No. 693 and our concerns set forth in this Final Rule. In that regard, we require NERC to deploy its Expedited Reliability Standards Development Process to quickly respond to the remand. As the Commission noted in previous orders, the use of planned or controlled load interruption is a fundamental reliability issue and, certainty regarding the loss of non-consequential load for a single contingency event is warranted.[30] Thus, using the Expedited Standards Development Process will more rapidly bring needed certainty to this fundamental reliability issue.

22. Below we discuss three concerns: (a) jurisdictional issues, (b) lack of technical criteria, and (c) the stakeholder process. The Commission also provides guidance on other acceptable approaches.

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[29] NERC Rules of Procedure, Section 1601 (effective January 31, 2012).

[30] *North American Electric Reliability Corp.*, 130 FERC ¶ 61,200 (2010) (March 2010 Order); *North American Electric Reliability Corp.*, 131 FERC ¶ 61,231 (2010) (June 2010 Order).

A. Jurisdictional Issues

23. A number of commenters express concern that the Commission is reaching beyond its FPA section 215 jurisdiction.[31] Commenters assert that the Commission options exceed its jurisdiction involving acceptable levels and types of service. Commenters seek assurance that the Commission's proposal does not infringe on matters reserved to the States and instead "only prescribe acceptable load shedding as it pertains to wholesale customers that are in a position to select interruptible or conditional firm transmission service."[32] NARUC states that "any NERC standard for shedding distribution level load must be guided by States and that a demonstration that interruption of the load will not cause instability, uncontrolled separation, or cascading failures on the bulk system is appropriate for a NERC standard."[33] NARUC adds that specifications of what retail load and what levels of retail load can be interrupted is a State determination that is not reviewable by the Commission. TAPS agrees with NERC that issues pertaining to whether it is permissible to plan to interrupt firm load involves conflicts among federal, provincial, state, and local governing bodies.[34]

24. The Commission disagrees that it is infringing on State Commissions or overstepping jurisdictional bounds. In this Final Rule, the Commission remands NERC's

[31] *See, e.g.,* Comments of NERC, NARUC, APPA and TAPS.

[32] NYPSC Comments at 5.

[33] NARUC Comments at 3-4.

[34] TAPS Comments at 9.

proposed footnote ‘b’ as an inadequate mechanism to address planned curtailment of firm demand and not responsive to the Commission’s directives in Order No. 693 regarding this matter. The Commission is not directing that NERC develop a specific solution or approach on remand. Thus, our remand of the NERC proposed modification to TPL-002-0b, Table 1, footnote ‘b’ is fully within the Commission’s authority pursuant to section 215(d)(4) to remand to the ERO for further consideration a modification to a proposed reliability standard that the Commission disapproves in whole or in part. Moreover, FPA section 215 gives the Commission jurisdiction over mandatory Reliability Standards to ensure reliability of the Bulk-Power System.[35] Consistent with its statutory authority, the Commission’s interest and focus in this proceeding is on the planned interruption of Firm Demand on the Bulk-Power System. The Commission views this matter in the context of Reliability Standard TPL-002-0b, which requires that in planning the system to withstand the loss of a single Bulk-Power System element, Bulk-Power System performance criteria must be met. If it is not met, a corrective action plan is required to address the Bulk-Power System performance criteria violation. Contingencies studied pursuant to Reliability Standard TPL-002-0b pertinent to Bulk-Power System facilities are subject to Commission jurisdiction under FPA section 215. In sum, the performance of the Bulk-Power System under the TPL-002-0b Reliability Standard is within the Commission’s jurisdiction.

[35] 16 U.S.C. § 824o(b)(1).

B. Lack of Technical Criteria

NOPR Proposal

25. In the NOPR, the Commission proposed to remand NERC's proposal to modify Reliability Standard TPL-002-0b, Table 1, footnote 'b.' The Commission stated that it believed that NERC's proposal does not meet the directives in Order No. 693 and the June 2010 Order and does not clarify or define the circumstances in which an entity can plan to interrupt Firm Demand for a single contingency.[36] In the NOPR the Commission expressed concern that NERC's proposed footnote 'b' lacks parameters. Without any substantive parameters governing the stakeholder process, the enforceability of this obligation by NERC and the Regional Entities would be limited to a review to ensure only that a stakeholder process occurred. The Commission noted that NERC appears to confirm this concern, as NERC explained that Regional Entities' involvement is limited to after-the-fact oversight by auditing the entity's implementation of footnote 'b' to determine if the planned interruption of Firm Demand was vetted through the stakeholder process.[37]

26. Further, in the NOPR the Commission stated that since the proposed footnote 'b' contains no constraints, it could allow an entity to plan to interrupt any amount of planned Firm Demand, in any location or at any voltage level as needed for any single contingency, provided that it is documented and subjected to a stakeholder process. The

[36] NOPR, FERC Stats. & Regs. ¶ 32,683 at P 11.

[37] *Id.* P 12.

Commission found this result remains contrary to the underlying Reliability Standard and prior Commission orders.[38] The Commission requested comment on this specific concern of the lack of technical criteria or parameters.

Comments

27. Some commenters agree with the Commission that there is lack of technical criteria to determine planned interruption of Firm Demand. For example, California SWP states that Reliability Standards "should ensure transparent criteria based on technical merits and not software limitations derived from a desire to mask [locational marginal pricing] price signals with socialized pricing or on *status quo* practices."[39] ITC believes that there is a need for defined parameters that will guide the review of exceptions and that will prevent planned interruptions from becoming commonplace.[40] Manitoba Hydro states that the characteristics of openness and transparency are indicators of a non-discriminatory planning process; however, these characteristics do not ensure that certain reliability criteria of the planned facilities will be met.[41]

28. Other commenters disagree with the Commission's concern that there is a lack of criteria to determine planned interruption of Firm Demand. NERC states that it does not believe that an exceptions process that provides defined criteria, with some allowances,

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[38] *Id.*

[39] California SWP Comments at 4.

[40] ITC Comments at 2.

[41] Manitoba Hydro Comments at 6.

could be crafted that would respect pre-existing decision making processes that occur at state and local jurisdictions. NERC argues that the decision to interrupt local load is essentially an economic decision – a quality of service issue, not a reliability issue.[42]

29. MISO disagrees that additional language would reduce the potential for inconsistent results and points out that registered entities already have many established requirements that govern the transmission planning processes.[43] MISO believes that if the Commission determines that criteria are needed, such criteria should be determined by the stakeholders in the regions though their established stakeholder processes.[44] EEI does not believe that specific criteria should be developed until a better understanding is obtained regarding the role of service interruptions as a reliability tool.[45] EEI believes that these are appropriate aspects of the NERC proposal that would be readily amenable to an initial implementation approach, followed by an adjustment period that would refine the overall process consistent with the Commission's concerns.

Commission Determination

30. We believe that openness and transparency do not alone ensure that bulk electric system performance criteria will be met to ensure system reliability. The Commission is not persuaded that developing technical criteria is unachievable. As the Commission

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[42] NERC Comments at 13.

[43] MISO Comments at 3.

[44] *Id.* at 5.

[45] EEI Comments at 10.

observed in the NOPR, NERC has thresholds in other reliability contexts, such as vegetation management pursuant to Reliability Standard FAC-003-1 which applies to all transmission lines operated at 200 kV and above. Likewise, NERC's Statement of Compliance Registry Criteria includes numerous thresholds for determining eligibility for registration.[46]

31. The Commission does not agree with EEI's recommendation to implement a stakeholder process that is absent technical criteria but then amend it later. While the Commission has, in other circumstances, approved a Reliability Standard and, as a separate action, directed NERC to develop a modification pursuant to section 215(d)(5) of the FPA, in such proceedings the Commission concluded that the proposed Reliability Standard was just, reasonable, not unduly discriminatory or preferential and in the public interest. In the immediate proceeding, however, we cannot make such a finding in light of the flawed stakeholder process provision.

32. In response to MISO's argument that such criteria should be determined by the stakeholders in the regions though their established stakeholder processes, the Commission would be amenable to such an approach if, for example, NERC and/or the Regional Entities developed an exception process that provides flexibility in decisions based on disparate topology or on other matters since they could utilize their technical

[46] *See, e.g.*, NERC Statement of Registry Criteria, section III. The Commission approved the Statement of Registry Criteria in Order No. 693. *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 95.

expertise to determine the reliability impact from one region to another. For these reasons, the Commission concludes that a more defined process is needed with NERC-defined technical criteria to determine planned interruption of Firm Demand. However, we conclude that the approach of allowing a decentralized process without any overarching parameters is unacceptable.

33. With regard to NERC's comment that the decision to interrupt local load is essentially an economic decision that is a quality of service issue, not a reliability issue, the Commission notes that in Order No. 693, we dismissed the argument that it may be preferable to plan the bulk electric system in such a manner that contemplates the interruption of some firm load customers in the event of a N-1 contingency, and that such interruption is based largely on the matter of economics, not reliability.[47]

C. Stakeholder Process

NOPR Proposal

34. In the NOPR, the Commission expressed concern that NERC's proposed footnote 'b' stakeholder process is insufficient to meet Order No. 693 and the June 2010 Order clarification that a regional difference, or a case-specific exception process that can be technically justified, to plan for the loss of firm services at the fringes of the systems is acceptable in limited circumstances.[48] The Commission also noted that nothing in the proposed footnote 'b' defines the stakeholder process, other than that it must be an open

[47] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1792.

[48] NOPR, FERC Stats. & Regs. ¶ 32,683 at P 19.

and transparent stakeholder process that includes addressing stakeholder comments.[49] The Commission noted that any meeting that is open to stakeholders could meet this criteria.

35. The Commission further stated that the lack of a defined stakeholder process could allow a transmission planner to develop a process that provides insufficient opportunity for stakeholder participation and transparency yet still comply with the standard. The Commission expressed its belief that nothing in the proposed footnote 'b' restricts the stakeholder process, other than that it must be an open and transparent stakeholder process that includes addressing stakeholder comments. The Commission requested comment on whether a stakeholder process is the appropriate vehicle to approve or deny exceptions to allow entities to plan to interrupt Firm Demand for a single contingency and if so, whether the proposed footnote 'b' would require any stakeholder due process.

Comments

36. Several commenters believe that NERC's proposed stakeholder process is the appropriate venue to approve or deny exceptions to interrupt planned Firm Demand. NERC and other commenters contend that building on existing stakeholder processes is appropriate, rather than creating new, duplicative processes. While EEI, APPA, and TAPS concur with or acknowledge the Commission's concerns about the inadequacy of the proposed stakeholder process, they nonetheless urge the Commission to approve

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[49] *Id.* P 20.

NERC's proposal stating that it reflects the considered expertise that instances of planned load shed are uncommon and not amenable to a one-size-fits-all approach.[50] NERC believes the introduction of an additional planning process may contribute to further delays and regulatory confusion. NERC states that "keeping decision-making with those most impacted by decisions regarding reliability and costs, lack of jurisdictional authority, and the existence of established open and transparent stakeholder processes – are the reasons NERC did not create a new stakeholder process."[51]

37. Duke Energy believes that the current Order No. 890-type process involving the local transmission planning collaborative is the appropriate stakeholder process. Duke Energy suggests that footnote 'b' should be revised to include a local regulatory authority process as the appropriate stakeholder process to allow entities to plan to interrupt Firm Demand for a single contingency. According to Duke Energy, in such a process a transmission planner would submit its plan to interrupt Firm Demand for a single contingency to its local regulatory authority that has jurisdiction over quality of service to local load prior to any actual interruption of Firm Demand.

38. BPA states that the stakeholder process will keep the decision local, where the parties involved understand the different factors that must be considered in deciding the

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[50] *See, e.g.*, EEI Comments at 3, TAPS Comments at 5, APPA Comments at 3.

[51] NERC Comments at 12.

proper path forward.[52] APPA maintains that these processes impose due process requirements on the transmission planner, including participation in an open and transparent stakeholder process that considers stakeholder comments.[53]

39. FRCC disagrees with the Commission that enforceability is limited since the process requires development of a record documenting the decisions and stakeholder comments and planning authority responses. According to FRCC, the result will provide NERC and the Commission substantive and procedural grounds to assess whether sufficient consideration was given to maintaining reliability.[54]

40. Some commenters believe that NERC's proposed stakeholder process is not the appropriate vehicle to approve or deny exceptions to interrupt planned Firm Demand. ITC argues that the stakeholder process is inadequately undefined to ensure that planned Firm Demand interruptions are kept to a minimum. Manitoba Hydro indicates that by acknowledging an exception for interruptible Firm Demand, NERC appears to recognize that the right to interrupt is not solely a reliability issue, but also a commercial or legal issue based on contractual rights.[55]

41. While TAPS encourages the Commission to accept NERC's proposed footnote 'b,' it shares the NOPR's concerns about the adequacy of the open and transparent

[52] BPA Comments at 4.

[53] APPA Comments at 5.

[54] FRCC Comments at 3.

[55] Manitoba Hydro Comments at 5.

stakeholder process and has argued for a decision-making role for transmission-dependent utilities in the Order No. 890 and Order No. 1000 planning processes to ensure that stakeholder processes do not result in a presentation of a decision followed by the transmission provider simply "rubber-stamping" the decision.[56] If the Commission determines that these objectives cannot be accomplished without more robust action from the Commission in this proceeding, TAPS urges the Commission not to remand the proposed footnote 'b,' but instead to accept NERC's proposal and direct NERC to submit a further modified footnote 'b' to address the parameters of the "open and transparent stakeholder process that includes addressing stakeholder comments."[57]

Commission Determination

42. The Commission is not persuaded that the stakeholder process is adequately defined. The Commission is concerned that the stakeholder process could undermine the system performance criteria of TPL-002-0b Reliability Standard. As the Commission stated in Order No. 693, one of the key reliability objectives of the TPL Reliability Standard is that the system can be operated following the loss of one element and supply projected firm customer demands and projected firm transmission services at all demand levels over the range of forecast system demands.[58] The Commission finds that the stakeholder process without appropriate parameters is inconsistent with the reliability

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[56] TAPS Comments at 5.

[57] *Id.* at 11.

[58] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1771.

objective to supply projected firm customer demands for the loss of one element. While the Reliability Standard requires that the system is planned so that the system can be operated following the loss of one element and supply projected firm customer demands, the proposed stakeholder process could defeat this by allowing a transmission planner to plan to shed as much load as needed so that the system can be operated to supply whatever customers remain.

43. The Commission agrees with TAPS to the extent it observes that the proposal could allow a transmission planner to utilize a new or existing stakeholder process that provides insufficient opportunity for a stakeholder to provide meaningful input. We conclude that the stakeholder process with no criteria to objectively assess whether varied results are arbitrary or based on meaningful differences is unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. Nothing in proposed footnote ‘b’ defines the stakeholder process, other than it must be an open and transparent stakeholder process that includes addressing stakeholder comments.

44. The Commission is not persuaded by FRCC’s comment that enforceability is not limited by proposed footnote ‘b’ and that development of a record will provide NERC “substantive and procedural” grounds to assess the outcome of the process. Neither FRCC nor any other commenter identifies the minimum procedural safeguards to assure an adequate level of stakeholder participation and consideration of stakeholder comment in the decision-making process. Moreover, even NERC, which states that it can conduct

after-the-fact audits, indicates that such audits would not explore substantive adequacy or the reliability basis for a decision to plan to shed Firm Demand.[59] Further, the Commission is not persuaded by APPA and BPA comments that local stakeholder participation and due process requirements imposed on the transmission planner are sufficient. Rather, the Commission believes that if a transmission planner invokes a process that provides for minimal stakeholder involvement, it could argue that it satisfied the provision, even if the transmission planner is the ultimate decision maker and simply 'rubber stamps' its own proposal to interrupt planned Firm Demand.

D. Guidance on Acceptable Approaches to Footnote 'b'

45. The Commission proposed three options in the NOPR for further guidance on acceptable approaches to footnote 'b.' In addition, the Commission requested comment on other potential options to solve the concerns outlined in the NOPR.

1. Existing Protocols to Develop Criteria/Quantitative Limits

46. In the NOPR, the Commission acknowledged that NERC considered a variety of limits but observed that NERC's establishment of some form of criteria for planning to interrupt Firm Demand could be an acceptable approach for footnote 'b.' The Commission requested comment on whether existing protocols such as the Department of Energy's Electric Emergency Incident and Disturbance Report (Form OE-417), which requires an entity to report a certain amount of uncontrolled loss of firm system loads, or

[59] NERC Data Response at 7-9.

NERC's Statement of Compliance Registry Criteria could provide guidance to NERC to devise criteria.

Comments

47. Commenters were unanimous that the examples of existing protocols would not be beneficial to devise criteria. NERC and others state that any bright-line megawatt limit would be inappropriate because the bright-line would be arbitrary.[60] Some commenters do not believe that existing protocols, such as the requirement in Form OE-417 should be used to determine criteria related to planned loss of Firm Demand.[61]

48. BPA, ITC, and Duke Energy comment that setting a quantitative limit would push transmission planners to plan to meet such a limit for a single contingency in all cases. Currently, transmission planners start from the premise that no load should be interrupted in the event of a single contingency. ITC believes that including such an acceptable lost load criterion as an option could lead to that option being chosen as the "default solution," i.e., allowing for a certain amount of acceptable interruption of Firm Demand without a stakeholder exception review process.[62] In the same vein, Duke indicates that a specific megawatt threshold may prohibit certain interruptions of Firm Demand that would be acceptable from a quality of service and local consequences perspectives.[63]

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[60] NERC Comments at 14.

[61] ITC Comments at 5; *see also* Hydro One and IESO Comments.

[62] ITC Comments at 5.

[63] Duke Comments at 6.

Commission Determination

49. The Commission is persuaded by the commenters that Form OE-417 or the Registry Criteria are not, by themselves, beneficial to use to devise criteria. The Commission also agrees that a bright-line criteria by itself does not present a viable option and would have the potential to constitute an acceptable *de facto* interruption and become commonplace to plan to interrupt Firm Demand. For example, if the bright-line criteria included up to 50 MW of planned interruptible Firm Demand under proposed footnote 'b', then planners may choose to automatically shed up to 50 MW of load as their first course of action for any single contingency event that would cause a violation of system performance criteria. This is not an acceptable outcome.

2. A Blend of Quantitative and Qualitative Thresholds

50. The Commission also sought comment on whether a blend of quantitative and qualitative thresholds to be used to interrupt planned Firm Demand would be an appropriate option for providing criteria that would be generally applicable, but also for allowing for certain cases that may exceed the criteria. For example, a Reliability Standard could require a process with a quantitative limitation on how much Firm Demand could be planned for interruption and the standard could provide an exception process where a registered entity would submit documents and explanation to the ERO or a Regional Entity for approval based upon certain considerations.[64] The Commission

[64] NOPR, FERC Stats. & Regs. ¶ 32,683 at P 18.

suggested that setting generally applicable criteria for when an applicable entity can plan to shed Firm Demand, coupled with an exceptions process overseen by NERC and the Regional Entities, could mean that few exception requests must be processed by NERC and the Regional Entities.[65] The Commission observed in the NOPR that this approach may satisfy the need for technical criteria while accounting for NERC's concerns about the difficulty of developing a one-size-fits-all criterion for limiting planned Firm Demand interruptions and the appropriateness and feasibility of managing and actively participating in each planning process.

Comments

51. California SWP indicates that standards must constrain the use of firm load shedding as a reliability solution in transmission planning and at the same time, require a transparent and clearly defined stakeholder process to support any such planned use of load shedding for single contingency events.[66] BPA suggests that, if the Commission does set a quantitative limit on planned interruption of Firm Demand, a limit based on a fraction of aggregated normal peak load would be one option that may be more effective and adaptable to all sizes of utilities.[67]

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[65] *Id.* P 27.

[66] California SWP Comments at 2.

[67] BPA Comments at 4.

52. Other commenters disagree that a blend is a good option. NARUC indicates that rather than inventing another stakeholder process by requiring NERC to set specific quantitative or qualitative requirements for distribution load shedding, NERC should look to State commissions and existing State curtailment plans to guide load shedding in contingency planning.[68] Duke Energy submits that a blend of quantitative and qualitative thresholds does not provide enough flexibility to permit the qualitative assessment of the loads and locations for which transmission planners may interrupt under their exercise of footnote 'b' because a blended threshold may still rely too heavily on a quantitative threshold for planned interruption of Firm Demand.[69] FRCC states it is not feasible to develop a single quantitative rule that would apply equitably to all stakeholders and regions.[70]

53. EEI believes that adopting a process that would provide greater clarity, reporting, and refinement would provide the specific information on the extent that the footnote 'b' issue presents itself. EEI also agrees with NERC that efforts to create a one-size-fits-all approach have less value than a process that ensures openness and transparency.

[68] NARUC Comments at 3.

[69] Duke Energy Comments at 7.

[70] FRCC Comments at 7.

Commission Determination

54. The Commission believes that setting a quantitative and qualitative threshold in developing a limited exception for planned interruption of Firm Demand may be a workable solution. First, qualitative thresholds could be used to overcome the concern discussed immediately above regarding the quantitative threshold becoming an acceptable *de facto* interruption of planned Firm Demand. By utilizing a blend, the planner must also meet the qualitative threshold which could consist of, for example, the submittal of documents and explanation to the entity ultimately deciding whether the planned load shed is acceptable. For example, if 100 MW of planned Firm Demand was permitted to be interrupted, the planner could not automatically and unilaterally shed up to 100 MW of planned Firm Demand each time system performance criteria would be violated. Under the blend concept, the Commission envisions that the planner would consider up to 100 MW of planned Firm Demand interruption along with other options to resolve the system performance criteria violation and submit its documentation and explanation to the entity deciding whether the planned load shed is acceptable. The concept of a blend of thresholds would prevent an acceptable *de facto* interruption of planned Firm Demand and avoid the difficulty of developing a one-size-fits-all criterion for limiting planned Firm Demand interruptions, but still allow for those limited circumstances to be reviewed in an exception process where a limited amount of planned interruption of Firm Demand may be acceptable.

55. We believe it is appropriate for the Regional Entities, with NERC as the final authority, to make determinations under a “blended” exception process. First, NERC and

the Regional Entities provide both objectivity in the decision-making process as well as the necessary reliability-focused expertise. Second, this should not overly burden NERC or Regional Entity resources as utilization of the planned load shed exception is – and would be – rarely utilized.[71] Further, we are not persuaded by the assertion that NERC would be conflicted as the ERO and also inserting itself in the process. NERC's ERO role would continue, in coordination with its current responsibilities in implementing other exceptions such as the Technical Feasibility Exception process under the Critical Infrastructure Protection Reliability Standards.

56. The Commission does not agree with BPA's suggestion of using quantitative thresholds based on a fraction of aggregated normal peak load. BPA's suggestion attempts to address the concerns of commenters that a bright-line threshold must be established that would be a one-size-fits-all criteria. For example, instead of a megawatt bright-line threshold for all entities, the ERO could establish a threshold based on a percentage of aggregated normal peak load. The Commission believes that it would be difficult to demonstrate that adoption of BPA's suggestion would be just and reasonable, not unduly discriminatory or preferential and in the public interest. If criteria were established that permitted a percentage of aggregated normal peak load as an acceptable threshold for planned interruption of Firm Demand, even a small percentage could equate

[71] *See, e.g.,* FRCC Comments at 4; MISO Comments at 4; BPA Comments.

to entire towns, cities or regions of load.[72] The Commission, therefore, does not support the planned interruption of Firm Demand based on a fraction of aggregated normal peak load. The Commission believes that an appropriate mechanism would be based on impact studies that consider minimizing planned interruption of Firm Demand within, and adjacent to, communities and small localities.

57. The Commission offers guidance to NERC to consider the option of a blend of quantitative and qualitative thresholds. An example of a qualitative threshold could include identifying geographical or topological "fringes of the system." While interruption at the fringes of the system may be expected by some consumers, not all customers necessarily have that same expectation. For example, we don't expect that many water treatment facilities or telecom switching stations normally plan to be interrupted for single contingency events.[73] While the Commission has offered one example of a qualitative threshold, NERC may explore other qualitative thresholds on remand. The Commission believes that a blend of quantitative and qualitative thresholds coupled with an exception process overseen by NERC and the Regional Entities would be a reasonable option to allow for the limited interruption of planned Firm Demand.

[72] For example, the PJM aggregated normal system peak load is approaching 160,000 MW, so a one percent threshold would equate to allowance of planned interruption for a single contingency of up to 1600 MW of load, which is the size of some entire towns, cities or regions.

[73] While we anticipate that such facilities are prepared for distribution-level blackouts, we are not aware that they are prepared for a transmission-level blackout.

Accordingly, the Commission directs the ERO to consider some blend of quantitative and qualitative thresholds.

3. Customer or Community Consent

58. In the NOPR the Commission also requested comment on whether a feasible option would be to revise footnote 'b' to allow for the planned interruption of Firm Demand in circumstances where the "transmission planner can show that it has customer or community consent and there is no adverse impact to the Bulk-Power System."[74] The Commission suggested that this would not require affirmative consent by every individual retail customer, but would recognize that either group would need to be adequately defined. The Commission requested comments on who might be able to represent the customer or community in this option and how customer or community consent might be demonstrated.[75] The Commission also requested comment on how it would be determined that firm demand shedding with customer consent would not adversely impact the Bulk-Power System. Additionally, the Commission requested comment on whether a customer who would otherwise consent to having its planning authority or transmission planner plan to interrupt Firm Demand pursuant to this option could instead select interruptible or conditional firm service under the tariff to address cost concerns.

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[74] NOPR, FERC Stats. & Regs. ¶ 32,683 at P 28.

[75] *Id.*

Comments

59. Several commenters agreed with the Commission that the customer or community consent should be required. ITC believes the customers or entities should be involved in a stakeholder process such as a representative group for the affected load or customers (community representatives or a separate load serving entity where the transmission provider is not an integrated utility), the public service/utility regulatory commission for the affected load, the RTO or ISO for the affected area, and any other affected entity. California SWP also supports notice to and consent of loads (or their wholesale representatives) that are planned to be interrupted for the loss of a single element.[76] In its comments, California SWP explains that it was "surprised to learn that in lieu of transmission upgrades, [its transmission planner] relied on interruption of SWP's large firm pump loads supposedly receiving the same California Independent System Operator (CAISO) transmission service as provided to SCE loads. At that time, SWP was not consulted about the planned curtailment of its firm loads as an alternative to a transmission upgrade, and thus had no opportunity to correct this error."[77]

60. Other commenters disagree that customer or community consent should be required. NERC states that it has no relationship with retail customers and, therefore, has no mechanism to bring retail customers into the conversation. NERC adds that both

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[76] California SWP Comments at 4.

[77] *Id.* at 2-3.

wholesale and retail customers are already involved in state processes which provide a forum for them to be heard.

61. Hydro One and the IESO submit that customer interests are managed by the relevant regulatory authority and consent is through regulatory approval. In all cases, steps are taken in planning, design, and operations of the system to ensure that Firm Demand shedding would not adversely impact the bulk electric system in addition to the fact that the customer also has other options such as to select interruptible service. NYPSC recommends that the Commission only prescribe acceptable load shedding as it pertains to wholesale customers that are in a position to select interruptible or conditional firm transmission service under Commission-approved tariffs.

62. FRCC states that the evaluation of the possible use of interruptible or conditional firm service instead of planned interruptions of Firm Demand is not warranted. According to FRCC, the adoption of a Firm Demand interruption alternative would inherently entail customer benefits from foregone project costs and the non-incurrence of environmental and other impacts. The customers would also generally enjoy a higher quality of service than traditional interruptible or conditional firm. Consequently, FRCC believes that applying any such rate in place of Demand interruption would present imponderable issues of quantification and application.

63. BPA does not believe that this proceeding is appropriate to decide issues related to service choice. BPA argues that the Commission has determined that the rate for conditional firm service be the same as the firm rate. BPA does not anticipate that the interruption of Firm Demand would occur on a frequent basis, if at all. Thus, BPA does

not believe that a customer should pay a different transmission rate under these circumstances. APPA states that footnote 'b' arms wholesale transmission customers and communities served at retail with information and studies prepared by the transmission planner, documenting the specific circumstances (i.e., specific Bulk Electric System Contingency events) under which interruption of Firm Demand may be needed to address bulk electric system performance requirements.

Commission Determination

64. We understand NERC's position that as the entity that addresses Bulk-Power System reliability, it does not have a mechanism to coordinate with customers. Likewise, how to define customers and community decisions and engage them in the NERC process could be challenging.[78]

65. At the same time, California SWP provides a compelling example of how a customer can be adversely affected by planned load shedding for Firm Demand if it was unaware its load would be interrupted until its load was actually shed. In contrast to California SWP's experience, a customer should have notice and understanding that the transmission planner plans to curtail certain Firm Demand in the event of a single

[78] As suggested in the NOPR, customer or community consent would not require affirmative consent by every individual retail customer, but the process NERC developed would recognize that either group would need to be adequately defined. We note that, although NERC comments that it addresses Bulk-Power System reliability, the process that NERC proposes will impact firm load service to retail customers.

contingency indentified in the system modeling under NERC's Transmission Planning requirements. NERC should consider these matters on remand.[79]

Summary

66. In sum, the Commission remands the proposed footnote 'b' and directs NERC to revise its proposal to address the Commission's concerns described above, subject to consideration of the additional guidance provided in this Final Rule.

67. As stated in the NOPR, NERC will need to support the revision to footnote 'b.' If there is a threshold component to the revised footnote, NERC would need to support the threshold and show that instability, uncontrolled separation, or cascading failures of the system will not occur as a result of planning to shed Firm Demand up to the threshold. In addition, if there is an individual exception option, the applicable entities should be required to find that there is no adverse impact to the Bulk-Power System from the exception and that it is considered in wide-area coordination and operations. Further, the Commission believes that any exception should be subject to further review by the Regional Entity or NERC.

III. Information Collection Statement

68. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an

[79] We will not consider the tariff-related comments as they are beyond the scope of this rulemaking.

agency.[80] The information contained here is also subject to review under section 3507(d) of the Paperwork Reduction Act of 1995.[81]

69. As stated above, the subject of this Final Rule is NERC's proposed modification to Table 1, footnote 'b' applicable in four TPL Reliability Standards. This Final Rule remands the footnote 'b' modification to NERC. By remanding footnote 'b' the applicable Reliability Standards and any information collection requirements are unchanged. Therefore, the Commission will submit this Final Rule to OMB for informational purposes only.

70. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: data.clearance@ferc.gov, phone: (202) 502-8663, or fax: (202) 273-0873].

IV. Environmental Analysis

71. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[82] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment.

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[80] 5 CFR § 1320.11.

[81] 44 U.S.C. § 3507(d).

[82] *Regulations Implementing the National Environmental Policy Act of* 1969, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986-1990 ¶ 30,783 (1987).

Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[83] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act

72. The Regulatory Flexibility Act of 1980 (RFA)[84] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[85] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[86] The RFA is not implicated by this Final Rule because the Commission is remanding footnote 'b' and not proposing any modifications to the existing burden or reporting requirements. With no changes to the Reliability Standards as approved, the Commission certifies that this

[83] 18 CFR § 380.4(a)(2)(ii).

[84] 5 U.S.C. § 601-612.

[85] 13 CFR § 121.201.

[86] *Id.* n.22.

Final Rule will not have a significant economic impact on a substantial number of small entities.

VI. Document Availability

73. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

74. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

75. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

VII. Effective Date and Congressional Notification

76. These regulations are effective [insert date 60 days from publication in **FEDERAL REGISTER**]. The Commission has determined, with the concurrence of the

Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

By direction of the Commission. Commissioner Norris is dissenting in part and concurring in part with a separate statement attached.

(S E A L)

Kimberly D. Bose,
Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning Reliability Standards Docket No. RM11-18-000

(Issued April 19, 2012)

NORRIS, Commissioner, *dissenting in part and concurring in part*:

The continued implementation and evolution of the mandatory reliability standards program enacted by Congress in 2005 has been at the forefront of our agenda since I arrived at the Commission in 2010. As we have grappled with the difficult issues raised by proposed new or revised standards, and as I have discussed these issues with regulated industry, state regulators, and the public, I have consistently heard a common theme: mandatory reliability standards come with costs that consumers ultimately must bear.

As I have thought about this issue, it has become clear to me that in any discussion of a new or revised mandatory reliability standard, there is always a tradeoff between the level of reliability to be achieved by that standard and the costs that the standard will impose. However, that tradeoff is rarely discussed explicitly in the standards development process or during the Commission's review of standards. But, we know that it is an implicit consideration of entities participating in the standards development process. I believe it is more appropriate to make those considerations, where they are relevant, explicit. Therefore, I have advocated for an open dialogue between NERC, the industry, and the Commission to consider the connection between the mandatory standards we approve to maintain and improve the reliability of the Bulk Power System and the costs required to meet those standards.

However, I have perceived some hesitancy in openly addressing costs when considering reliability matters. This is not surprising, as there are no easy answers to these tough questions, and regulators and industry charged with assuring reliability will always be hesitant to be perceived as sacrificing reliability in an effort to save on costs. While I am not advocating for a cost-benefit threshold for approving reliability standards, I do not believe that we can ignore the costs of proposed mandatory reliability standards as we consider whether they are "just, reasonable, not unduly discriminatory or preferential, and in the public interest".[1] These are issues with real world implications,

[1] *See* 16 U.S.C. 824o(d)(2).

not just for the reliability and security of our Nation's electric grid, but for the day-to-day struggles of local communities to balance the economic realities of many competing obligations.

I am compelled to raise these issues in this proceeding because I believe that the Transmission Planning (TPL) Reliability Standard footnote 'b' addressed in today's order presents a stark example of the tradeoffs that sometimes must be made between increasing levels of reliability and the costs that come with achieving them. As such, I hope my comments today will help generate a dialogue on how economics and reliability fit together when considering mandatory reliability standards.

In today's order, I agree with the majority's decision to remand proposed TPL footnote 'b' because it is vague, potentially unenforceable, and lacks adequate safeguards to determine when planning to shed firm load would be permitted. However, I am concerned that, in allowing for an exception to the TPL standards requirement that firm load must be maintained under N-1 scenarios, the order does not sufficiently recognize that this is both an economic and reliability issue, and must allow for a balancing of the economic and reliability considerations involved.

There may be cases where planning to avoid shedding firm load in all N-1 scenarios will impose significant costs on customers, with perhaps little added reliability benefit for those customers. In such instances, I believe that wholesale transmission customers and local communities with retail load service should be empowered to consider the economic tradeoffs between incurring costs to avoid shedding firm load versus planning to shed firm load, as long as that decision does not adversely impact the reliability of the Bulk Power System. Simply put, if a customer seeks to avoid significant costs, and can do so without impacting its neighbors, the customer should be making that decision. Today's order fails to adequately acknowledge the economic consequences of having to invest in significant facility upgrades to avoid shedding firm load under certain N-1 scenarios that may be rare or unlikely and that would have only local impacts.[2]

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[2] *Transmission Planning Reliability Standards*, Order No. 762, 139 FERC ¶ 61,060, at P 33 (2012) ("With regard to NERC's comment that the decision to interrupt local load is essentially an economic decision that is a quality of service issue, not a reliability issue, the Commission notes that in Order No. 693, we dismissed the argument that… such interruption is based largely on the matter of economics, not reliability.") I also note that the brief Commission findings in Order No. 693 failed to acknowledge or sufficiently address this issue, leaving the uncertainty we are still faced with today. *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 1791-1794 (2007).

Accordingly, in my view, the Commission should have directed NERC to revise footnote 'b' to address two broad concerns. First, wholesale transmission customers and retail load should have the ability to choose whether to shed firm load during an N-1 contingency where that decision will not adversely impact the Bulk Power System. Second, the decision to shed firm load must be validated to ensure that there is no adverse impact on the Bulk Power System. Absent this reliability check, the planning of firm load shedding should not be permitted, because reliability of the Bulk Power System is paramount. While NERC, the Regional Entity, and/or the local planning authority must be involved in the reliability check, these entities would not be expected to be involved in the economic decision.

Additionally, I agree with various comments filed in response to the NOPR that firm load shedding is and should be used rarely or infrequently. I do not expect that any new process that NERC may propose to determine whether firm load shedding is permitted would result in a rush by entities seeking to plan to shed firm load. In other words, I do not expect this exception to "swallow the rule" under the TPL standards that firm load may not be planned to be shed for N-1 contingencies.

Finally, the concerns I note above regarding the failure to consider both the economic and reliability aspects of a decision to plan to shed firm load extend to the specific guidance provided in the order. The guidance in the order with respect to what would constitute an allowable exception fails to provide a realistic means for entities to balance these economic and reliability considerations. Instead, I would have provided that an entity could submit its plan to shed firm load for a single contingency to its relevant regulatory authority or governing body prior to any actual interruption.[3] The politically accountable regulatory authority or governing body would have then made the determination, based upon economics and in the best interests of its customers, as to whether firm load shedding should be permitted. Those determinations would be subject to oversight and review by NERC, the Regional Entity, and/or the planning authority to ensure that they will not adversely impact the Bulk Power System.[4]

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[3] *See e.g.*, Duke Energy Corporation Dec. 22, 2011 Comments, Docket No. RM11-18-000.

[4] NERC may propose an alternative to Commission guidance that is equally efficient and effective at addressing the Commission's reliability concerns. Order No. 693 at P 31.

For these reasons, I respectfully dissent in part and concur in part.

John R. Norris, Commissioner

Document Content(s)

Standards Announcement

Project 2010-11– TPL Table 1 Order
TPL-002-1b, footnote ‘b’ and TPL-001-3, footnote 12

Formal Comment Period Open: July 31, 2012 – August 29, 2012

Now Available

A formal comment period for **TPL-002-1b** – Single Performance Following Loss of a Single BES Element for footnote ‘b’ and **TPL-001-3a** – Transmission System Planning Performance Requirements for footnote 12 is open through **8 p.m. Eastern on Wednesday, August 29, 2012.**

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Wednesday, August 29, 2012.** Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

Data Request to Transmission Planners and Planning Coordinators

A draft data request to collect data to assist the SDT in its work was posted for an abbreviated comment period in accordance with Section 1600 of the NERC Rules of Procedure, through July 9, 2012. The draft data request was revised as appropriate to reflect industry comments and is being issued for formal response concurrent with this posting. The timing of the formal data request response will allow for the data to be evaluated by the SDT in the same timeframe as the responses to this posting.

The drafting team will consider all comments and determine whether to make changes. If the drafting team does not make significant changes, the standards will be posted for a 45-day comment period and initial ballot.

Background

FERC Order No. 762, issued April 19, 2012, remanded TPL-002-0b to NERC as vague, unenforceable and not responsive to the previous Commission directives on this matter. The Standards Committee directed the Standards Drafting Team (SDT) to revise footnote ‘b’ in accordance with the directives of Orders No. 693 and 762. The SDT was also charged with revising the corresponding footnote 12 of TPL-001-2 in order to prevent the remand of TPL-001-2.

In revising the footnotes, the SDT adopted a philosophy of minimal changes to the actual footnote itself. This was done to minimize confusion as to what was changed, for ease of reading and following the footnote, and for formatting within the actual standards documents. Instead, the SDT revised the footnote by developing an attachment to the footnote containing changes in response to the Commission orders. It should be noted that attachments to standards are an extension of the Requirements and thus are binding to applicable entities.

Project 2010-11 is an important part of the ERO's strategic goal to be responsive to regulatory authority directives in an expeditious manner in order to reduce the amount standards-related directives and to provide an adequate level of reliability.

Additional information can be found on the project page.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Individual or group. (53 Responses)
Name (41 Responses)
Organization (41 Responses)
Group Name (12 Responses)
Lead Contact (12 Responses)
Contact Organization (12 Responses)
Question 1 (45 Responses)
Question 1 Comments (49 Responses)
Question 2 (45 Responses)
Question 2 Comments (49 Responses)
Question 3 (44 Responses)
Question 3 Comments (49 Responses)
Question 4 (45 Responses)
Question 4 Comments (49 Responses)
Question 5 (0 Responses)
Question 5 Comments (49 Responses)

Individual
hello
NAT
Group
TVA Transmission Reliability Engineering & Controls
Tim Ponseti, VP
Bulk Transmission Engineering
No
TVA believes that the Stakeholder process is burdensome and should not be required for all levels of footnote b use. TVA beleives that the Stakeholder process should only be used for larger amounts of planned load drop. TVA would like to propose the following: For load loss of less than 50 MW - only TP approval is required; for load loss up to 100 MW - PC approval is required; for load loss up to 300 MW - RRO approval is required. Any load loss over 300 MW would require both RRO & NERC approval. The Stakeholder process would be required for any load loss of 100 MW or more. TVA is basing these levels using OE-417 as a starting point - which must be filed for an uncontrolled load loss of 300 MW as well as load shedding of 100 MW or more implemented under emergency operational policy. TVA believes that the 300 MW is the maximum amount of load that can be dropped without obtaining special permission from both NERC and the RRO.
No
Please see comment for question #1. TVA believes that TPs should be able to drop some load without having to go thru a burdensome process. Only the larger load drop levels should require a Stakeholder review.
No
Under Item #2 - TVA is not sure how to properly address “health, safety, and welfare of the community” from an regulatory standpoint. Please clarify what this would require - such as number of hospitals without emergency backup, etc? Also please see answer to question #1 - TVA beleives that only larger load drops should require a Stakeholder review.
No
Please see answer to question #1. TVA believes that the requirements of 25 MW as well as any Bulk contingency over 300-kV is much too burdensome. TVA beleives that only larger load drops should require a Stakeholder review.
Please see answer to question #1. TVA beleives that only load drops of higher magnitudes go thru the Stakeholder and regulatory review.
Group
Puget Sound Energy
Sunitha Kothapalli

Transmission Planning
Individual
Aaron Staley
Orlando Utilities Commission
Yes
Yes
Yes
Data element 5 should probably read. "List any Future Plans or future system changes to mitigate the need for Firm Demand Interruption under footnote 'b'". There can be cases where there is no planned future project to relive the problem, or it could be expected that load will go down or changes on neighboring systems will relieve the problem.
Yes
Comment #1: The maximum threshold should be in the Footnote, not in the Attachment. Comment #2: I think the role identified for the Regional Entity is appropriate. Comment #3: I like the concept that regulatory approval is not required until year one. However I think either the ordering of language or the formatting needs to be changed to make it clear that the year one applies to only those that need regulatory approval. Maybe change the section to read... "Section III Firm Demand Interruptions under footnote 'b' that meet either or both of the criteria below are required to have approval by the applicable regulatory authority or governing body responsible for retail electric service issues. The regulatory approval is required prior to the use of that remedy in Year One of a Corrective Plan in the Planning Assessment. (Existing 1 & 2) (Existing RE Review)
Individual
Chifong Thomas
BrightSource Energy, Inc.
No
We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest deleting this sentence. Assigning a fixed "not to exceed" number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others. A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, "[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events". It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fix maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving "safe harbor" to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the "not to exceed" amount.
No
We suggest removing item 5, "A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction". Given that the "applicable regulatory authorities or governing bodies responsible for retail electric service issues" are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns and different authorities. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for approving retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?

No
We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the "applicable regulatory authorities or governing bodies responsible for retail electric service issues".
No
While we do not disagree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to approval of the use of Firm Demand interruption under footnote 'b'. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load. Requiring the Regional Entity to approve the Non-Consequential Load Loss under footnote b in TPL-002 (Footnote 12 in TPL-001-3) is duplicative and would increase the work load of the Regional Entities without improving reliability. The TP and PC are already required to make available to the affected stakeholders, verification that TPL Reliability Standards performance requirements will be met following the application of footnote 'b' (see Section II.6) and the assessment of potential overlapping uses of footnote 'b' with adjacent planners" (see Section II.8), it is hard to imagine what type of review and verification is required to show that "there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity's footprint".
The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2. Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV inconsistent with P1. The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 2 The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column. The new definition of Non-consequential Load Loss compared to the last version seems to have deleted the reference to Loads that may be lost during transient conditions due to under-frequency load shedding (UFLS), while the reference to Load Loss due to under-voltage load shedding (UVLS) is retained. As a result Load Loss due to UFLS would be part of Non-consequential Load Loss, and will not be allowed under single contingency. Because UFLS may also be triggered during transient simulations, please change the definition for Non-consequential Load Loss to read: "Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load or frequency sensitive Load, or (3) Load that is disconnected from the System by end-user equipment." It is also understood that load loss due to UVLS or UFLS or load that are disconnected from the system by customer equipment are not to be used in meeting steady state reliability requirements. Therefore, in Table 1, please change header-note "i" to read: "The response of voltage sensitive Load and Frequency sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements."
Individual

Jose H Escamilla
CPS Energy
Yes
Yes
Yes
Yes
Individual
Mark Westendorf
MISO
No
Transmission planning that relies on planned or controlled interruption of non-consequential firm load following loss of a single transmission facility should not be acceptable and removal of footnote 12 should be considered or a modification to allow its use only in conjunction with a petition to FERC to waive (on an exception basis) the requirement to maintain firm load service for a specifically identified system configuration issue warranting Footnote 12's application. If it is determined that a footnote provision is required in the standard, we agree with the description and components of the Stakeholder Process in the body of the footnote, but reserve judgment on the value of the "x" that sets the maximum amount of MW load loss. Also, we have comments on the reference to Attachment I. Please see our comments under Q5.
No
(1) The process presented in Section I of Attachment I is overly prescriptive. This Section needs only to stipulate that the proposed utilization of the footnote be reviewed through an open and transparent stakeholder process developed or approved by the Regional Entities (since the RE will eventually need to review and assess the reliability impact of such utilization), with supporting information. (2) There is no basis to support allowing the utilization of the footnote in the Near-Term Transmission Planning Horizon of the Planning Assessment only. The footnote itself leaves the time frame wide open, and does not explicitly or implicitly restrict its utilization to only the Near-Term horizon. Often, in the long-term planning horizon, when approval for transmission addition or reinforcement cannot be obtained for whatever reasons, utilization of the footnote is considered and adopted, subject to stakeholder's and regulatory authority's approvals. Note that it is impractical to add or reinforce transmission facilities in a near-term planning (e.g. Year 0ne) time frame and hence the proposed provision does not allow for utilizing the footnote for the interim period before new or reinforced transmission facilities are put in place. We suggest to remove the word "Near-Term". (3) Requirement 8 of the Transmission Planning Standard TPL-001-3 requires notification and response requirements for a Planning Coordinator and/or Transmission Planner for the Planning Assessment to any registered entity having a reliability interest. Attachment I does not recognize this requirement. Attachment I must be coordinated with this administrative requirement.
No
Again, this Section is overly prescriptive. This Section needs only to stipulate at a high level, the kind of information needed to support the proposed utilization of the footnote, leaving much of the detail to the application process overseen by the Regional Entities (given the RE will eventually need to review and assess the reliability impact of such utilization). We suggest the SDT to reduce this Section, or remove this altogether with appropriate insertion into Section I that address a general need for supporting information to be specified by the RE's review process.
No
We generally agree with the instances for which approval or interruptions is required, but do not agree with the requirement to seek regulatory approval. In general, when the footnote is proposed to be utilized as an interim measure until transmission facilities can be added or reinforced, regulatory approval must be sought in advance. Having this requirement in a reliability standard not only is

unnecessary, but also introduces regulatory requirements (which provides no reliability benefit or basis) in a reliability standard. NERC reliability standards should focus only on BES reliability, not any regulatory requirements. Section III should therefore stipulate a high-level requirement for the proposing entity to submit the proposal to the RE for review and concurrence. Along with the submission, the RE may require the proponent to include a copy of appropriate regulatory approval (which the entity should have already obtained). The conditions (1) and (2) for seeking regulatory approval can be retained, but now become the criteria for seeking review and concurrence by the RE. Additionally, Attachment 1 requires that the ERO develop a methodology on evaluation criteria to be published for determining Adverse Reliability Impacts for approval by the ERO. Planning Assessments are performed on an annual basis. The Attachment 1 process and ERO methodology may require a lengthy approval process that must be repeated on an annual basis.
(1) The process described in Attachment 1 may be more suited for inclusion in the Rules of Procedure, similar to the process required for seeking BES facility exceptions. We urge the SDT to consider moving Attachment 1 into a proposed RoP instead of stipulating it in the standard. (2) It may be more appropriate to develop a Standards process that covers the technical aspects of using a footnote 12 and leave regulatory review and approval to FERC and State agencies.
Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
NPCC reviewed the posted documents, and has no comments for this posting.
Individual
Jennifer Wright
San Diego Gas & Electric
No
We don’t support the changes.
No
We don’t support the addition of stakeholder process language.
No
We don’t support the addition of stakeholder process language.
No
In FERC Order 762, FERC rejected NERC’s footnote (b) and urged “...NERC to develop modifications responsive to the Commission’s directives in Order No. 693 and our concerns set forth in this final rule.” The NERC SDT has done little to address FERC’s concerns and instead has resubmitted the same document with additional language. Order 693 directed NERC to develop modifications to TPL-002-0, which clarify footnote (b). As redrafted, footnote (b) does not address FERC’s concerns. For example, footnote (b) continues to use the term “Firm Demand,” which describes all forms of demand whether served by the faulted element or not. On the contrary, “consequential load loss” is load, which is removed as a result of a fault. Clearly, these are different concepts and the new language does not comply with FERC’s directive. FERC’s position has been that non-consequential load loss through load shedding shall not be allowed as an exception to TPL-002-0. Also, FERC has stated that the interruption of Firm Transmission not be allowed as an exception. But, Footnote (b) continues to say, “Curtailment of firm transfers is allowed ...”. Another inconsistency. Beyond the differences between what FERC directed NERC to do and what NERC did, as written, footnote (b) would introduce “stakeholder interests” into tranmission reliability even if those interests do not promote reliability. The TPL standards identify the Planning Authority and Transmission Planner as the entities responsible for meeting the standards and makes no mention stakeholders. To meet the reliability objectives of the standard, the Planning Authority and Transmission Planner are subject to Measures

and the Compliance Monitoring Process. In FERC Order 762, FERC determined "...that openness and transparency do not alone ensure bulk electric system performance criteria will be met..." and was "...not persuaded that developing technical criteria is unachievable." Although FERC does not disagree with adding a stakeholder process, clearly, they do not endorse one and prefer a technical approach to creating the exception under footnote "b".
Individual
Patrick Brown
Essential Power, LLC
No
Although we agree with the majority of the content of the footnote, we're not sure that using a specific amount of load as the bright-line threshold is appropriate. For example, if we make the limit 25 MW, this will have a different impact on different entities, in different regions. For a small TP that may only have a total of 200 MW of load, 25 MW is a significant amount of their overall obligation. For an area with 40,000 MW of load, 25 MW is hardly significant. Additionally, the nature of the load must be taken into consideration as well. Some types of load are more acceptable to lose than others; again, this may vary from region to region. Although we don't have a specific recommendation or solution regarding these issues, I would urge the SDT to take these into consideration in their next revision. The sentence that starts with "When interruption of Firm Demand is utilized..." is confusing as it seems this sentence should only refer to the limited circumstances mentioned within footnote b
Yes
Yes
No
This solution requires filing with a regulatory body for any extra interruptions. This seems to be a lot of effort and language for a contingency event that the system is supposed to be able to handle.
As written, this change is complex and will be difficult to execute without additional turmoil on the planning end and offers limited clarification. Some additional issues to consider; 1. Should this level of contingency allow isolation/removal of load or generation if not part of the outage? 2. Should additional generation be allowed to be removed, again considering the contingency level?
Group
Southwest Power Pool Reliability Standards Development Team
Jonathan Hayes
Southwest Power Pool
Yes
As a concept we agree with the stakeholder process. We would like clarification on why only the Near Term was used for non-consequential load loss and not both Near and Long term. It seems that depending on the time frame we would be held to different requirements of the standard.
Yes
See comment From question 1
No
We need clarification on the term planner in item 8 of section 2. Since the term isn't capitalized we would like to know if this was intended to mean Transmission Planner or a adjacent Planning Coordinator for identifying a seams issue. We would like see item 2b of section 2 removed this item isn't relevant to the standard and goes beyond the purpose of this standard. We understand that this is included for curtailment of load during emergency conditions (EOP001 Attach 1) but feel it is unnecessary in planning.
No
Need clarification around why the 25MWs threshold on generation was thrown into load interruption topic. Looking at the registry criteria for generation the threshold should be 20Mws for a single unit and 75 MWs for aggregated units. Not sure where the 25MWs threshold came from for generation. The 25 MW threshold in Section III is duplicative of the registration limit for generation in the ERO Statement of Compliance Registry Criteria. It is submitted for comment at this time but will not be

finalized until after the above mentioned data request is complete and the final value will be submitted for industry comment and approval in the next posting. The GOP registration criteria is 20MWs. Whereas the registration criteria for LSEs and DPs is 25MWs. There appears to be some co mingling of criteria. Additionally this raises the question of whether x =25MWs. Please clarify which you intended to use. We are concerned that getting retail service regulatory authority approval in a quick manner could be difficult. We are also concerned that if it does get caught in the process of being approved and there is no time to construct, that we would not want to be found out of compliance due to something that is out of our control.
We agree the distinction between consequential and non- consequential is necessary. We don't agree that you should plan for non-consequential load loss/shed. You shouldn't have to interrupt firm service for n-1 contingency.
Individual
Keith Morisette
Tacoma Power
No
The layout of Table 1 with "No 12" does not actually indicate that load loss is allowed for those specific contingencies. Also the wording of the footnote appears to require all Non-Consequential Load Loss to go through the attachment 1 process, not just P1.1 to P1.5, P2.1 and P3.1 to P3.5. Instead P1.1 to P1.5 and P3.1 to P3.5 should say "Yes per Attachment I" and Footnote 12 should be eliminated entirely. Since P2.1 is a new requirement with Version TPL-001-03, the recent NERC survey did not capture utilities currently using Non-Consequential Load Loss to address opening a line without a fault. Furthermore, some utilities may not identify problem lines until their first assessment using TPL-001-3. P2.1 should have a new footnote reading "For this contingency, load which is served radial from a remaining single source line may be shed as if it were Consequential load." Technical Background: Parallel transmission lines serving remote load commonly will not perform with a P2-1 contingency, particularly when the strong source is opened. These issues are particularly common with load in rural settings and the cost to meet urban reliability expectations will be disproportionally expensive. Utilities will be encouraged to configure their system radially, which will be less reliable to meet this rare contingency. FERC has not specifically addressed load shedding associated with open ended lines. In order 693 the Commission was responding to the contingencies in TPL-001-1 that included footnote b. In order 762 and the NOPR RM12-1-000, FERC continues to reference applicability of footnote b to the TPL-001 defined single contingencies, but was otherwise prepared to accept Firm Load Loss for the single contingencies in TPL-001-2 P2.2 to P2.4. In the TPL-001-2, the category of "P2-Single Contingency" expanded to include both a new contingency of an open ended line, and various bus and breaker faults that previously were considered as Multiple Contingency. Based on our experience the likelihood of a line opening is significantly less than for line equipment faults. In addition, during human error caused line open events, personnel are on-site to affect quick restoration. This standard should not impose an upper limit because any planned large load shedding will be reviewed and approved by the applicable regulatory authority. Pending the survey outcome, a limit of 3000 MW consistent with the CIP-002-5 Critical Asset level may be useful if the SDT believes an upper limit is needed.
No
Completing the entire stakeholder process on an annual basis, before the TPL study can be finalized, is not feasible due to long and unpredictable timelines for public involvement and regulatory approval. The stakeholder process should only be repeated when the technical basis as outlined in section II have changed, or when there are new stakeholders. There are cases on the fringes of the system where Firm Demand Interruption as the preferred alternative in both the long term and short term, not as a temporary patch in Corrective Action Plan. To address these issues, Section I should read as: Before the use of Firm Demand interruption is allowed as an element in the Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of this mitigation is reviewed through an open and transparent stakeholder process. The responsible entity shall document the stakeholder process which shall include the following: 1. Meetings must be open to all affected stakeholders including applicable regulatory Authorities or governing bodies responsible for retail electric service issues. 2. Notice must be provided in advance of meetings to all affected stakeholders, including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda

with: a. Date, time, and location for the meeting b. Specific applications of the planned Firm Demand interruption under footnote 12 c. Provisions for a stakeholder comment period 3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote 12 (as shown in Section II below) must be made available to meeting participants. 4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns. 5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction. During each Planning Assessment, the Transmission Planner or Planning Coordinator shall update the information outlined in Section II. If the annual hours of exposure to or the amount of Firm Demand has increase above the previously disclosed level(s), a new Stakeholder process shall be completed within one Calendar year. Every three years the stakeholder process shall reoccur to allow new stakeholders input to the process.
No
Item II.2.b Since this is a stakeholder process, each stakeholder can make an assessment for themselves about the effect of Firm Demand interruption on the health, safety and welfare of the community. This requirement is too vague to be enforceable. Item II.5 Particularly in the case of P2.1 contingencies, utilities may not have any plans to eliminate load shedding "at the fringes of various systems" as the FERC NOPR noted would be acceptable.
No
As noted in our response to question 2, regulatory approval is often a slow process and is not conducive to repeating annually. Instead of a 25 MW limit, a 300 MW limit that corresponds to the reporting level of firm demand in EOP-004 is more appropriate.
FERC order 762 states that "to plan for the loss of firm service at the fringes of various systems would be an acceptable approach." The newly defined contingency P2.1 requiring analysis of open ended line sections should allow load shedding of the load on the line section as suggested in the FERC order.
Individual
John Burnett
Los Angrles Department of Water and Power
No
We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest deleting this sentence. Assigning a fixed "not to exceed" number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others. A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, "[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events". It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fix maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving "safe harbor" to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the "not to exceed" amount.
No
We suggest removing item 5, "A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction". Given that the "applicable regulatory authorities or governing bodies responsible for retail electric service issues" are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?
No
We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of

customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the "applicable regulatory authorities or governing bodies responsible for retail electric service issues".
No
While we do not disagree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to approval of the use of Firm Demand interruption under footnote 'b'. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load. Requiring the Regional Entity to approve the Non-Consequential Load Loss under footnote b in TPL-002 (Footnote 12 in TPL-001-3) is duplicative and would increase the work load of the Regional Entities without improving reliability. The TP and PC are already required to make available to the affected stakeholders, verification that TPL Reliability Standards performance requirements will be met following the application of footnote 'b' (see Section II.6) and the assessment of potential overlapping uses of footnote 'b' with adjacent planners" (see Section II.8), it is hard to imagine what type of review and verification is required to show that "there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity's footprint".
The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2. Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV in P1 is of no value. The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 3 The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column.
Individual
Nazra Gladu
Manitoba Hydro
No
The maximum limit 'x' MW should vary with system load level and voltage. For example, an 'x' MW interruption would be a very small fraction of a 5000 MW system load level compared to a 1000 MW load level. Similarly, interruption of 'x' MW could be equal to surge impedance loading of a 230 kV line, where as it would be a fraction of a EHV transmission line loading.
No
A stakeholder process should not be required in jurisdictions where a legislation already authorizes interruptions, as consent of stakeholders cannot override legislation. If Firm Demand interruptions require the approval of regulatory authority as described in Section III (for interruptions over 25 MW or if voltage level of the contingency is greater than 300 kV), the stakeholder process described in Section I would become a redundant process. Does Section I exclude Firm Demand interruptions addressed under Section III?
No

1 a. It would be very difficult to estimate the annual hours of exposure at or above a certain load level. 2 b. An assessment on the health, safety, and welfare of the community should not be part of a reliability assessment – this is purely subjective. 3 & 4. In situations where load interruption is a new proposal, historical data will not be available. What does the SDT expect here? 5. Is there a requirement to mitigate? If there is a requirement to mitigate, the required time frame is not identified.
No
The Section III states that regulatory authority approval is required for interruptions over 25 MW or if voltage level of the contingency is greater than 300 kV. However, a regulatory authority cannot approve interruption of Firm Demand unless it already has such jurisdiction that is conferred upon them by legislation. A reliability standard cannot confer that jurisdiction. Further, the regulator is already part of the proposed stakeholder group and will have input into the proposal. The Section III requires the Regional Entity to review the proposed use of Firm Demand interruption under footnote 'b'. What impact does it have on the Regional Entity to necessitate a review, if the stakeholders have already agreed to a process, TPL Reliability Standards performance requirements have been verified as in Section II.6, and potential overlapping uses have been assessed with adjacent planners as in Section II.8. What criteria will the Regional Entity use to make their assessment of Adverse Reliability Impacts and potential cumulative effects given the above TPL performance must be met? This requirement can lead to inconsistent decisions between regions.
Please clarify if an entity must set up a stakeholder process if Firm demand interruption is not used as an element of the Corrective Action Plan. As I understand it, the footnote b in TPL 002 will be replicated in the other relevant TPL standards once it is approved. When it is included in the other TPL standards, will it be customized to each standard, or will it appear exactly the same in each standard? Footnote 12 of TPL-001 as currently drafted seems a bit disjointed or incomplete – i.e. its referring to Non Consequential Load Loss and then it refers you to an Attachment for the calculation of Firm Demand interruption without providing a connection between the two concepts .
Individual
Test
TEST
Individual
Michael Falvo
Independent Electricity System Operator
No
Specific to the language used in footnote b, we agree with the concept of an approval process for determining the acceptable level of Firm Demand interruption applicable in a jurisdiction, and do not agree with prescribing a fixed MW threshold for a continent-wide acceptable Firm Demand interruption. Therefore, we recommend removing the last sentence in footnote b) which reads "In no case can the planned Firm Demand interruption under footnote 'b' exceed 'x' MW." and also the same sentence from Attachement 1 section III. We believe there should not be a fixed limit on the amount of Firm Demand interruption, for reasons explained below in answers to Questions 4 and 5. As part of a reliability standard, the footnote should clarify the conditions under which load curtailment will be allowed, including mention of processes necessary to manage special circumstances. We generally agree with the reference to Attachment 1, but have concerns about the components of the Stakeholder Process described in Attachment 1, for reasons described in answers to Questions 2, 3 and 4.
No
(1) The process presented in Section I and the rest of Attachment I is overly prescriptive and lengthy. As part of a reliability standard, the footnote and process must focus on the impact that Firm Demand interruption (or Load Rejection) would have on the reliability of the Bulk Electric System and this aspect is covered in Section III. This Section needs only to stipulate that the proposed utilization of the footnote be reviewed through (a) an open and transparent stakeholder process and (b) approved by a relevant reliability authority such as the ERO, Regional Entity or applicable governmental authority since this authority will eventually need to review, assess and approve the reliability impact on the interconnected BES of such utilization, with supporting information. Reliability issues and their assessment and approvals should be dealt with by the applicable reliability authority. Details of other

aspects of Firm Demand interruption, mainly the Stakeholder review and approval process and issues pertaining to the quality of service, economic and welfare impacts of Firm Demand interruption, assessment of alternatives (including their economic and welfare impacts), etc. should be dealt with by the regulatory authority or government body of each jurisdiction (in particular, in non-US jurisdictions), as is the normal practice for all other Transmission Planning activities. (2) There is no basis to support allowing the utilization of the footnote in the Near-Term Transmission Planning Horizon of the Planning Assessment only. The footnote itself leaves the time frame wide open, and does not explicitly or implicitly restrict its utilization to only the Near-Term horizon. Often, in the long-term planning horizon, when approval for transmission addition or reinforcement cannot be obtained for whatever reasons, utilization of the footnote is considered and adopted, subject to stakeholders' and regulatory authorities' approvals. Note that it is impractical to add or reinforce transmission facilities in a near-term planning (e.g. Year 0ne) time frame and hence the proposed provision does not allow for utilizing the footnote for the interim period before new or reinforced transmission facilities are put in place. We suggest removing the word "Near-Term".
No
Again, this Section is overly prescriptive. This Section needs only to stipulate at a high level, the kind of information needed to support the proposed utilization of the footnote, leaving much of the detail to the application process overseen by the applicable reliability authority to review and assess the reliability impact of such utilization. We suggest the SDT to reduce this Section, or remove this altogether with appropriate insertion into Section I that address a general need for supporting information to be specified by the RA's review process. Also note that use of a "stakeholder process", as per FERC's concerns, must be crisp and clear.
No
We generally agree with the instances for which approvals or interruptions are required. Approval is to be granted by the Reliability Coordinator or applicable reliability authority. (1) In general, when the footnote is proposed to be utilized as an interim measure until transmission facilities can be added or reinforced, regulatory approval must be sought in advance. Having this requirement in a reliability standard not only is unnecessary, but also introduces regulatory requirements (which provides no reliability benefit or basis) in a reliability standard. NERC reliability standards should focus only on BES reliability, not any regulatory requirements. Section III should therefore stipulate a high-level requirement for the proposing entity to submit the proposal to the Reliability Coordinator for review and concurrence. The conditions (1) and (2) for seeking explicit regulatory approval can be retained, but now become the criteria for seeking review and concurrence by the applicable reliability authority. (2) We suggest deleting Item 1 in the first paragraph (with its a and b bullets) and just indicating that planned Firm Demand interruption requires approval if it is greater than 25 MW (or other threshold). Requirements for approval of the use of Firm Demand interruption should be independent of the voltage level of the contingency. (3) We propose deleting the sentence in the second paragraph "In no case can the planned Firm Demand interruption under footnote 'b' exceed 'x' MW". A fixed limit on the allowable size of Firm Demand interruption can not be technically justified for the whole continent and each case should be assessed to determine if its impact on reliability of the bulk transmission system is acceptable or not. The impact of each case on the affected customers (economic, welfare, etc.) will also be reviewed and approved by the regulatory authority or governmental body of each jurisdiction and a "reliability" standard must not impose limits and restrictions pertaining to these aspects. (4) The third paragraph proposes that the Regional Entity should review each case of Firm Demand interruption and verify that there are no Adverse Reliability Impacts. We propose instead that the transmission planner or planning coordinator study the BES performance requirements and the reliability impacts of Firm Demand interruption, including its correct operation, miss-operation, and the failure to operate. The transmission planner should then submit a report of this assessment to the Reliability Coordinator for review and approval.
(1) We'd like to reiterate our support for allowing load interruption for a single contingency with sufficient review/oversight and under acceptable conditions, including no adverse impact on the reliability of the bulk electric system. The reliability aspects (BES performance requirements) should be reviewed/approved by the Reliability Coordinator. However, issues pertaining to economics or externalities which may not be directly reliability-related are always available for review and debate by the stakeholders via the regulatory processes and subject to approval by the regulatory authority of each jurisdiction (particularly those in Canada and Mexico). (2) Furthermore, we request that Table 1 of TPL-001-3 (previous TPL-001-2 approved by NERC BOT) be corrected for EHV contingencies in

P2, P4 and P5 categories to allow the same load interruption that is allowed for the related P1 contingency. Table 1 currently does not allow any load to be interrupted for an EHV single contingency if the primary circuit breakers fail to clear the fault (Category P4, “Fault plus stuck breaker”). But if load X is allowed to be interrupted for a single EHV transmission line contingency (Category P1), it should be allowed to interrupt the same load X if the primary breaker fails and the fault is cleared by other breakers. Similarly, if the same breaker has an internal fault or there is a fault on the same bus section (Category P2) or there is a failure of a relay (Category P5), which results in the loss of the same EHV transmission line, it should be allowed to interrupt the same load X. (3) We suggest that NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve them. Accordingly, we believe that the focus of the foot note ‘b’ should be that interruption of load must not adversely impact the reliability of the interconnected BES because reliability of supply to load and/or supply continuity is mandated by the jurisdictional authority. (4) We submit that the scope of NERC’s mandatory standards does not extend to assessing or setting requirements for non-jurisdictional entities, unless such facilities are necessary for the operation of the interconnected BES or have an adverse impact on its reliability. For Canadian entities there are regulatory requirements and processes under the purview of the relevant regulatory authorities that we believe are adequate. Accordingly, customer interests are protected and are not subject to unilateral decisions of the transmission planner. In all cases, steps are taken at the planning, design, and operations stages of system development such that non-consequential Firm Demand interruption would not adversely impact the BES and the affected customer has been given the opportunity to avail themselves of other options under the transmission development rules in the relevant jurisdictions. (5) The requirements of the footnote (including attachment) will amount to a mandate to construct additional transmission which is inconsistent with Section 215 (i) (2) of the US Federal Power Act which specifically does not authorize the ERO “to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services. (6) We suggest that NERC should not include and/or address load reliability or load supply continuity requirements within the BES Reliability Standards. In Canada, these requirements and approvals are with relevant reliability or regulatory authority. If NERC feels obligated to include such requirements for load reliability issues in US, then we propose that non-jurisdictional entities must be exempted from these requirements similar to the provisions in NUC 001. (7) The proposed implementation plan conflicts with Ontario regulatory practice respecting the effective date of the standard. It is suggested that this conflict be removed by appending to the implementation plan wording, after each “applicable regulatory approval” in the Effective Dates Section A5 of both draft standards, to the following effect: “, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.”
Group
Salt River Project
Bob Steiger
ERC
No
We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest deleting this sentence. Assigning a fixed “not to exceed” number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others. A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, “[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events”. It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fix maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving “safe harbor” to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the “not to exceed” amount.

No
We suggest removing item 5, “A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction”. Given that the “applicable regulatory authorities or governing bodies responsible for retail electric service issues” are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?
No
We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the “applicable regulatory authorities or governing bodies responsible for retail electric service issues”.
No
While we do agree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to give approval of the use of Firm Demand interruption under footnote ‘b’. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load.
The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is admitted for single contingency events in Category P1, but not for fault events in Category P2. Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV in P1 is of no value. The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the appearance of footnote 12 for EHV in P1 is of no value. The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column.
Individual
Kirit Shah
Ameren
No
We believe that the NERC Glossary contains an adequate definition for Firm Demand, which does not include Interruptible Demand or Demand-Side Management Load. We do not believe that Interruptible Demand or Demand-Side Management Load needs to be mentioned in the footnote b) as these types of Demand are not Firm Demand. Interruptible Demand can be cut at any time and may contain Demand-Side Management components, and may be direct controlled by the System Operator.
No
We request that Item 1 be modified to include representatives of stakeholders because it may not be practical to open a meeting to all affected stakeholders. The new sentence of Attachment 1 should read, “Meetings must be open to all affected stakeholders, or their representatives, including applicable regulatory authorities or governing bodies responsible for retail electric service issues.”

Also, requirements for a meeting location would sem to eliminate electronic partipation via webex. It would seem more practical for a TP or PC to host a specific webex to present and discuss the issues associated with the need to drop Firm Demand. Further, we request that a MW threshold be included before the Section I stakeholder process would begin, and believe that a minimum threshold of 10 MW of Firm Demand to be cut would be a reasonable value to initiate a stakeholder process. Levels below 10 MW would be considered as “noise” in the planning horizon. We believe that an approval should be obtained in the Section I process, which would eliminate the need for Section III. By requiring an approval of the appropriate local governing bodies responsible for retail service issues (including rates), there is no need to agree on a cap to limit the amount of Firm Demand dropped.
No
We request that Items 5 and 7 also include information regarding estimated costs and schedule for implementation. Any permitting issues associated with the alternatives should also be included. Any previous attempts to build facilities but were blocked should also be part of the record.
No
We do not believe that section III is needed, and particularly if an approval is included as part of the section I process. We do not subscribe to dropping Firm Demand (non-consequential load) for single contingency events, and do not see a need to include a voltage threshold as part of the contingency requirements. All single contingencies in Category B should be applicable.
To clarify, the Stakeholder Process should not be initiated until the amount of Firm Demand expected to be interrupted by the TP or PC as mitigation reaches a threshold of 10 MW. However, at that point, the Stakeholder Process should commence, but not without incorporating the need to obtain approvals from the stakeholders, regardless of the amount of load to be interrupted beyond the 10 MW threshold level, and regardless of the voltage level of the transmission elements involved in the contingency event(s). As drafted, the Stakeholder Process appears to be silent on receiving approvals to drop load of less than 25 MW. We believe that this is an invitation to trouble for the industry. For example, if a TP or PC were to have a contingency for which the mitigation is to interrupt 15 MW of Firm Demand, all the stakeholders would be called in just to inform them that their load is subject to interruption, but their displeasure is not relevant, because the 25 MW interruption level had not been reached, and approval is not required. Thus, we believe that as drafted Stakeholder Process needs some additional work before we could support it.
Individual
Thad Ness
American Electric Power
Yes
AEP believes it can support the language at this stage, but would like to revisit this after the MW threshold has been determined.
Yes
Yes
No
AEP is concerned that not all Regional Entities are the same in regards to their engineering and planning staff, and is not confident that they would all have the resources necessary to perform the required analysis. AEP is concerned by any attempt to require that a Regional Enity adhere to processes and prodecures that have not yet been established. FERC has made comments in the past regarding requirements places upon regional entities (RRO), and while this standard does not yet apply, is does indirectly obligate them to rules and procedures not yet established.
Individual
John Delucca
LCEC (Lee County Electric Cooperative
“No comment as we have no Firm Demand / Load customers.”

No comment as although we are a Firm Demand customer of another entity, we have no Firm Demand / Load customers and therefore would not perform the Stakeholder Process
No comment as although we are a Firm Demand customer of another entity, we have no Firm Demand / Load customers and therefore would not perform the Stakeholder Process
No comment as although we are a Firm Demand customer of another entity, we have no Firm Demand / Load customers and therefore would not perform the Stakeholder Process
“None”.
Group
MRO NSRF
WILL SMITH
MIDWEST RELIABILITY ORGANIZATION
Yes
The NSRF agrees with the ‘x’ MW statement in footnote b. The NSRF suggests a maximum threshold value of 300 MW because this is the load loss threshold that the DOE deems to be significant enough to warrant a NERC system event investigation. To support the inclusion of planning to use up to 300 MW of firm load shedding, registered Transmission Planning entities or regional planning entities should provide a TPL type analysis that demonstrates the use of planned firm load shedding allows BES equipment to stay within emergency thermal, voltage, and frequency ranges, and would not cause instability, uncontrolled separation, and cascading as defined in the FPA Section 215.
No
Order 890 already requires Transmission Planners to solicit the input of affected stakeholders on TPL standards. Order 890 does not provide prescriptive details regarding the stakeholder process for the TPL standards, which includes footnote ‘b’. In additions, there is no clear justification to indicate that the process with regard to footnote ‘b’ warrants more prescription stakeholder process details than the rest of the TPL standards. So, the NSRF suggests that Section II be removed. If Section I is not removed, then NSRF suggests at least replacing “all affected stakeholders” with “all known affected stakeholders” or “appropriate known affected stakeholders” because an entity can develop a list of all known affected entities for compliance purposes and document that the meeting was open to them and that they were notified. An entity cannot demonstrate that a stakeholder meeting is open to unknown stakeholders or that it notified unknown stakeholders. The use of “all” in mandatory zero defect standards is not appropriate in NERC standards, especially when potential large diverse populations such as affected stakeholders must be considered.
No
Order 890 already requires Transmission Planners to solicit the input of affected stakeholders on TPL standards. Order 890 does not provide prescriptive details regarding the information that should be included in the stakeholder process for the TPL standards, which includes footnote ‘b’. Stakeholders that participate in stakeholder meeting can ask for any information that they want regarding the proposed use of Firm Demand interruption. They do not need a third party to prescribe what information they need or want. So, the NSRF suggests that Section II be removed. If Section II is not removed, then the NSRF suggests that at least Items 2b, 6, and 8 be removed from the listing. • Item 2b – The scope and content expectation for an assessment of the potential impact of the proposed Firm Demand interruption on the health, safety, and welfare of the community is basically broad, nebulous, and vague. The stakeholders would raise any specific, relevant questions or concerns in these areas if they exist without a prescriptive stipulation for this information in the TPL-002 standard. • Item 6 – The verification of that the TPL performance requirements will be met by the use of Firm Demand interruption is superfluous. Proposal to use Firm Demand interruption to meet the TPL-002 performance requirements would always be the result of identifying (i.e. verifying) what Firm Demand interruption is needed to meet the TPL-002 performance requirements. • Item 8 – Potential overlapping uses of footnot ‘b’ with adjacent planners will not always exist and would probably be rare. In addition, whenever the situation would exist, then any applicable adjacent planners would be affected stakeholders and would have the opportunity to attend the stakeholder meeting and raise any questions or concerns in that meeting without the stipulation of this information in the TPL-002 standard.
No
The NSRF suggests that Section III be removed for the following reasons. • The types of transmission

projects that would be needed to avoid proposing the use of the Firm Demand interruption under footnote ‘b’ are expected to be high cost, long lead time Corrective Action projects. Therefore, consideration of the any necessary approvals from regulatory authorities or governing bodies responsible for approving the Corrective Action project is a prerequisite and essential to any discussion or stiputlations regarding disapproval of the use of footnote ‘b’ proposal. The proposed TPL-002 text for Section III does not include any language to address this crucial aspect of any footnote ‘b’ approval sipulations. • The diversity of applicable regulatory authorities and governing bodies, as well as their justicitional scope or criteria with respect to the approval of interrupt retail electic service (as well as transmission Corrective Action projects), are too diverse and complex to be appropriately addressed by proposed Approval stipulations in the TPL-002 standard. If Section III is not removed, then the NSRF suggests the following changes. • Include the subject of approvals of Corrective Action projects that are necessary to negate the need for approval of the proposed Firm Demand interruption. • Replace the criteria regarding the voltage level of the relevant Contingency with criteria regarding the amount and type of Firm Demand that would be subject to interruption. The voltage level of the applicable Contingency elements are not material to impact on the affected load. • Replace the applicable amount of Firm Demand interruption criteria from 25 MW to at least 100 MW. There are many radial fed loads that are much geater that 25 MW and there are no stackholder meetings and required approvals for allowing the loads to be fedd radially (subject to interruption for Category B contingencies) rather than being network fed. The DOE threshold for requiring formal system event analysis is 100 MW of load dropping. So, why should the TPL-002 standard required special approvals to allow less than 100 MW of load be subject to interruption to assure BES reliability? • Change the text of “in Year One of the Planning Assessment” to “in the ten year planning horizon of the Plannign Assessment”. The planning assessments may reveal that the need to use of Firm Demand interruption will occur in Year 2, Year 3 or beyond (e.g. when a significant previously unforecast load increase is forecast to occur before any needed Corrective Action project could be initiated and implemented). • The NSRF is concerned that the current wording, “Corrective Action in Year One of the Planning Assessment” could be interpreted to require an annual stakeholder process review and approval. The NSRF suggests that the standard drafting team provide some language regarding a specific period that is expected for reaffiming the approval of the Firm Demand interruption. A review interval of at least every five years should provide reasonable business certainty and allow for future transmission construction if needed. The specific defined period of review should allow entities to operate in an effective manner. The NSRF is also concerned about the condition where approval was granted and then removed. Would an entity be instantly non-compliant to the TPL standards? If this is a possibility, the Standard Drafting Team should add a grace period that allows an entity to credibly construct a project to remain compliant.
The NSRF has concerns that over regulation of footnote “b” or “12” could cause lost opportunities for legitimate growth. An example condition would be the development of a large load in a relatively weak transmission area. Many times new large loads need open undeveloped areas to locate. Without the footnote “b” or “12” option, could an entity be forced to turn away legitimate load growth? The key being that an entity could serve the new large load under normal conditions with easy quick upgrades, but would need 5 – 7 years to construct additional transmission to meet N-1 conditions? Therefore the entity would need to turn away new growth because of over regulation on footnote “b” or “12”.
Individual
Andrew Z. Pusztai
American Transmission Company
No
ATC agrees with the ‘x’ MW statement in footnote ‘b’ , however, supports a maximum threshold value of 300 MW because this is the load loss threshold that the DOE deems to be significant enough to warrant a NERC system event investigation.
No
Order 890 already requires Transmission Planners to solicit the input of affected stakeholders on TPL standards. Order 890 does not provide prescriptive details regarding the stakeholder process for the TPL standards, which includes footnote ‘b’. In addition, there is no clear justification to indicate that the process with regard to footnote ‘b’ warrants a more prescriptive stakeholder process than the rest of the TPL standards. So, ATC recommends that Section I be removed. If Section I is not removed,

then ATC suggests replacing “all affected stakeholders” with “all known affected stakeholders” because an entity can develop a list of all known affected entities for compliance purposes and document that the meeting was open to them and that they were notified. An entity cannot demonstrate that a stakeholder meeting is open to unknown stakeholders or that it notified unknown stakeholders. The use of “all” in mandatory zero defect standards is not a good practice, especially when large diverse populations of affected stakeholders are considered.
No
Order 890 already requires Transmission Planners to solicit the input of affected stakeholders on TPL standards. Order 890 does not provide prescriptive details regarding the information that should be included in the stakeholder process for the TPL standards, which includes footnote ‘b’. Stakeholders that participate in stakeholder meetings can ask for any information they want regarding the proposed use of Firm Demand interruption. Therefore, ATC recommends that Section II be removed. If Section II is not removed, then ATC recommends that Items 2b, 6, and 8 be removed from the listing. • Item 2b – The scope and content expectation for an assessment of the potential impact of the proposed Firm Demand interruption on the health, safety, and welfare of the community is broad, nebulous, and vague. The stakeholders would raise any specific, relevant questions or concerns in these areas if they exist without a prescriptive stipulation for this information in the TPL-002 standard. • Item 6 – The verification that the TPL performance requirements will be met by the use of Firm Demand interruption is superfluous. Proposal to use Firm Demand interruption to meet the TPL-002 performance requirements would always be the result of identifying (i.e. verifying) what Firm Demand interruption is needed to meet the TPL-002 performance requirements. • Item 8 – Potential overlapping uses of footnote ‘b’ with adjacent planners will not always exist and would probably be rare. In addition, whenever the situation would exist, any applicable adjacent planners would be affected stakeholders and would have the opportunity to attend the stakeholder meeting and raise any questions or concerns in that meeting without the stipulation of this information in the TPL-002 standard.
No
ATC recommends that Section III be removed for the following reasons. • The types of transmission projects that would be needed to avoid proposing the use of the Firm Demand interruption under footnote ‘b’ are expected to be high cost, long lead time Corrective Action projects. Therefore, consideration of the any necessary approvals from regulatory authorities or governing bodies responsible for approving the Corrective Action project is a prerequisite and essential to any discussion or stipulations regarding disapproval of the use of footnote ‘b’ proposal. The proposed TPL-002 text for Section III does not include any language to address this crucial aspect of any footnote ‘b’ approval stipulations. • The diversity of applicable regulatory authorities and governing bodies, as well as their jurisdictional scope or criteria with respect to the approval of interrupt retail electric service (as well as transmission Corrective Action projects), are too diverse and complex to be appropriately addressed by proposed approval stipulations in the TPL-002 standard. If Section III is not removed, then ATC recommends the following changes. • Include the subject of approvals of Corrective Action projects that are necessary to negate the need for approval of the proposed Firm Demand interruption. • Replace the criteria regarding the voltage level of the relevant Contingency with criteria regarding the amount and type of Firm Demand that would be subject to interruption. The voltage level of the applicable Contingency elements are not material to impact on the affected load. • Replace the applicable amount of Firm Demand interruption criteria from 25 MW to at least 100 MW. There are many radially fed loads that are much greater than 25 MW and there are no stakeholder meetings or required approvals for allowing the loads to be fed radially. The DOE threshold for requiring formal system event analysis is 100 MW. So, ATC believes the TPL-002 standard should not require special approvals to allow less than 100 MW of load to be interrupted to assure BES reliability. • Change the text of “in Year One of the Planning Assessment” to “in the ten year planning horizon of the Planning Assessment”. The planning assessments may reveal that the need to use of Firm Demand interruption will occur in Year 2, Year 3 or beyond (e.g. when a significant previously unexpected load increase is forecast to occur before any needed Corrective Action project could be initiated and implemented). • ATC is concerned that the current wording, “Corrective Action in Year One of the Planning Assessment” could be interpreted to require an annual stakeholder process review and approval. ATC suggests that the standard drafting team provide some language regarding a specific period that is expected for reaffirming the approval of the Firm Demand interruption. A review interval of at least every five years should provide reasonable business

certainty and allow for future transmission construction if needed. The specific defined period of review should allow entities to operate in an effective manner.
Individual
James Tucker
Deseret Generation & Transmission Cooperative
No
We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest deleting this sentence. Assigning a fixed “not to exceed” number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others. A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, “[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events”. It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fix maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving “safe harbor” to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the “not to exceed” amount.
No
We suggest removing item 5, “A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction”. Given that the “applicable regulatory authorities or governing bodies responsible for retail electric service issues” are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?
No
We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the “applicable regulatory authorities or governing bodies responsible for retail electric service issues”.
No
While we do not disagree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to approval of the use of Firm Demand interruption under footnote ‘b’. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load. Requiring the Regional Entity to approve the Non-Consequential Load Loss under footnote b in TPL-002 (Footnote 12 in TPL-001-3) is duplicative and would increase the work load of the Regional Entities without improving reliability. The TP and PC are already required to make available to the affected stakeholders, verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’ (see Section II.6) and the assessment of potential overlapping uses of footnote ‘b’ with adjacent planners” (see Section II.8), it is hard to imagine what type of review and verification is required to show that “there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity’s footprint”.

: The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2. Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV in P1 is of no value. The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 3 The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column.
Individual
Brian Keel
Salt River Project
No
Additional comment from SRP for Q #5.
No
Additional comment from SRP for Q #5.
No
Additional comment from SRP for Q #5.
No
Additional comment from SRP for Q #5.
The new definition of Non-consequential Load Loss compared to the last version seems to have deleted the reference to Loads that may be lost during transient conditions due to under-frequency load shedding (UFLS), while the reference to Load Loss due to under-voltage load shedding (UVLS) is retained. As a result Load Loss due to UFLS would be part of Non-consequential Load Loss, and will not be allowed under single contingency. Because UFLS may also be triggered during transient simulations, please change the definition for Non-consequential Load Loss to read: “Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load or frequency sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.” It is also understood that load loss due to UVLS or UFLS or load that are disconnected from the system by customer equipment are not to be used in meeting steady state reliability requirements. Therefore, in Table 1, please change header-note “i” to read: “The response of voltage sensitive Load and Frequency sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.”
Individual
Andrew Gallo
City of Austin dba Austin Energy
Yes
Yes
No
Some of the information for inclusion in the Stakeholder Process is too burdensome and of limited value. In particular, 2b and 4 can be deleted because the requested information may not be available -- particularly if it is new load growth.

No
The 25 MW threshold for Approval of Interruptions of Firm Demand under Footnote ‘b’ is too low. It should be increased to 50 MW because there is an elaborate Stakeholder process to work through the reliability concerns.
Individual
Anthony Jablonski
ReliabilityFirst
No
ReliabilityFirst has a major issue/concern with Attachment 1, Section 3 (specifically the last paragraph regarding approval). This section requires the Regional Entity to review each proposed use of Firm Demand interruption under footnote 12 in order to verify that there are no Adverse Reliability Impacts. The paragraph goes on to require the Regional Entity to make its determinations and evaluation of Adverse Reliability Impacts using a published methodology approved by the ERO. First, since the Regional Entity is not a user, owner or operator of the BES, ReliabilityFirst believes the Regional Entity should not have requirements placed upon them. Furthermore there is no guidance on what is required to be placed within the published methodology. ReliabilityFirst believes this verification is outside the Regional Entity scope as delegated by the ERO. ReliabilityFirst believes that if such verification by the Regional Entity is required, it should be specifically laid out in the NERC Rules of Procedure and not an attachment within a standard.
Group
SERC EC Planning Standards Subcommittee
Jim Kelley
PowerSouth Energy Cooperative
No
We do not agree with this approach since there is no technical basis for allowing load shedding. It is all an administrative process which could result in inconsistencies from area to area. If a single contingency results in a local network becoming temporarily radial, then load shedding within the local network should be allowed. A limitation of up to some maximum amount of load shedding (to be determined) should be imposed. This would provide a technical basis for load shedding, which would help ensure consistency.
No
We recommend using a technical basis for load shedding instead of a Stakeholder Process.
No
We recommend using a technical basis for load shedding instead of a Stakeholder Process.
No
We recommend using a technical basis for load shedding instead of a Stakeholder Process. However, if a Stakeholder Process is used, the approval thresholds are correct. The Stakeholder Process should not even be initiated for less than these threshold levels.
The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Individual
Kayleigh Wilkerson
Lincoln Electric System
No
LES suggests the following changes to Footnote B/12 to further clarify the drafting team’s intent. Under Footnote B/12, recommend the first sentence be modified to state “An objective of the planning

process is to minimize the likelihood and magnitude of interruption…". Additionally, please clarify the reference to the Near-Term Transmission Planning Horizon while remaining silent on the Long-Term Transmission Planning Horizon. Does Appendix 1 apply to the Long-Term Transmission Planning Horizon as well as the Near-Term Transmission Planning Horizon?
Yes
Although LES agrees in general with the description and components included as part of Section I, we suggest the following wording changes to enhance Section I. Recommend the drafting team delete item 2(c) as it is duplicative of item 4 which is more succinctly worded. Also, recommend additional wording be added to the end of item 3 to provide meeting participants with advanced notice of the information. As an example, "information…must be made available to meeting participants [ten days prior to the meeting]."
Yes
No
For item 1(b) in Section III, LES requests that the drafting team clarify why approval by the regulatory authority for a generator contingency is based on the high-side voltage of the GSU rather than the generator capacity. LES believes the generator capacity, rather than the high-side voltage of the GSU, provides a more consistent basis for determining necessity for approval from the applicable regulatory authority or governing body. Additionally, LES asks for further clarification as to whether the steps referenced for Year One of the Planning Assessment extend to Year Two and beyond.
Individual
Milorad Papic
Idaho Power Co.
Yes
Maximum threshold for Planned Firm Demand interruption should be based on a previous year recorded peak demand. For instance for recorded peak demand of more than 3,000 MW the maximum treshold should be greater than 300 MW.
Yes
Yes
Yes
Individual
Martyn Turner`
LCRA Transmission Services Corporation
No
Footnote 12 is applied in column labeled "Non-Consequential Load Loss Allowed." However, the last sentence of the proposed Footnote 12 switches from using the terms Consequential Load Loss and Non-Consequential Load Loss to using the term "Firm Demand." The term "Firm Demand" should be revised to "non-Consequential Load Load loss." In addition, the application of Footnote 12 to the P3 contingency category should be removed.
No
In the Proposed Revision to the Standard, Footnote 12 is applicable to the use of Non-Consequential Load Loss to relieve criteria violations resulting from P1, P2, and P3 category contingencies, however, Footnote 12 and Attachment I switch terms and begins using "Firm Demand." Though it may be reasonable to characterize Non-Consequential Load Loss as a subset of Firm Demand not all Firm Demand is Non-Consequential Load Loss. The term "Firm Demand" as used in Footnote 12 and Attachment I should be replaced with "Non-Consequential Load Loss." Application of the term "Firm Demand" in Footnote 12 and Attachement 1 introduces an ecomonic criteria to the TPL-001 Reliability Standard. For intstance, the interruption of "Firm Demand" as defined in the NERC Glossary may not

require Non-Consequential Load Loss, however, this is an economic decision between the parties involved in the Firm Demand contract. In addition, a Transmission Planner or Tranmission Owner may or may not be a party to the Firm Demand contract. The process outlined in Attachment 1 applies to the P3 contingency category (through the application of Foontote 12) and thus represents a significant and substantive change in the reliability standard over previous standards. The reference to Footnote 12 should be deleted from the P3 contingency category.
No
Requirement 1 only requires that the Transmission Planner provide system load data, however, assumptions about system dispatch are also relevant. Requiring load without dispatch will not provide a complete understanding of the conditions under which Footnote 12 will apply. As a reliability standard, the Transmission Planner is required to find a range of plausible system conditions under which a criteria violation may be resolved. The requirement (1a) to provide an estimate of the exposure creates an overly burdensome requirement to investigate a wider range of possible operating conditions than is currently performed. Requirement 2a and 2b are overly burdensome on at Transmission Planner/Transmission Owner who does not directly serve retail loads by placing a requirement on the Transmission Planner/Transmission Owner to provide data that is outside of its control to develop or maintain.
No
See previous comments about use of the term “Firm Demand”.
The primary objection to Footnote 12 is twofold: 1. Application to the P3 contingency. This contingency is a Category C contingency under the current NERC TPL-003 standard and allows for load shedding. Thus, the proposed standard revision is a significant and substantial increase in the reliability standard. 2. Use of the term “Firm Demand” as opposed to “Non-Consequential Load Loss.” The NERC Glossary defines Firm Demand as “That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions” and Demand as “The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time.” Thus interruption of Firm Demand may not result in Non-Consequential Load Loss. Therm “Firm Demand” should be replaces with “Non-Consequential Load Loss.”
Group
Southern Company
Antonio Grayson
Operations Compliance
No
Southern does not agree with this Stakeholder Process approach since there is no technical basis for allowing load shedding. It is all an administrative process which could result in inconsistencies from area to area. A more technical based approach was the one taken by the SDT in an earlier draft - temporarily radial concept. If a single contingency (Category B) results in a local network becoming temporarily radial, then load shedding within the local network should be allowed since it would not have any impact to the reliability of the transmission grid. A limitation of up to some maximum amount ('x' MW) of load shedding (to be determined) should be imposed. This would provide a technical basis for load shedding, which would help ensure consistency from area to area. Furthermore, this would provide a method for defining the "fringes" of the power system.
No
Southern recommends using a technical basis for load shedding (see comment in Question 1 above) instead of a Stakeholder Process.
No
Southern recommends using a technical basis for load shedding instead of a Stakeholder Process.
No
Southern recommends using a technical basis for load shedding instead of a Stakeholder Process. However, if a Stakeholder Process is used, the approval thresholds given in the draft seem appropriate. Furthermore, we believe the Stakeholder Process should not even be initiated for less than these threshold levels. Lower amounts of load and lower voltage contingencies do not need to be taken through a Stakeholder Process.

The use of load dropping should be limited to being only an interim solution while a project is being completed and nothing else can be done.
Individual
Jonathan Fidrych
Tri-State Generation & Transmission Association, Inc.
No
There are several points that we disagree with in terms of the Stakeholder Process in the body of the footnote. First, the footnotes are not written in a manner so as to clearly be only applicable to Planning Standards. Many parts of the footnotes and the Attachment I can be misconstrued as Operational requirements. For example, the sentence that states “Curtailment of firm transfer…” should state “Planned curtailment of firm transfer…” Second, we disagree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest removal of this sentence. Assigning a fixed “not to exceed” number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others. A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, “[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events”. It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fixed maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Lastly, in an effort to develop a clearer and more transparent compliance standard, it is recommended that the additional requirements imposed by this footnote be broken into separate requirements set forth within the body of the standard itself. Do not imbed requirements in footnotes.
No
We disagree with Section I of Attachment I to the extent that there currently are several other venues through which stakeholder input is mandated. In addition, we do not believe NERC Reliability Standards have the authority to dictate stakeholder outreach processes. For several reasons, including the time required for public input, permitting, acquisition, and construction, most transmission projects take several years to build. TPs will develop plans to mitigate BES performance violations, but those plans may not be able to be constructed in time. The Footnotes do not allow planners to design temporary mitigation to accommodate real world construction issues, which are often complex in nature due to competing interests.
No
We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the “applicable regulatory authorities or governing bodies responsible for retail electric service issues”.
No
We disagree with the instances for which Approval of Interruptions is required as proposed by Section III of Attachment I. TPs will develop plans to mitigate BES performance violations, but those plans may not be able to be constructed in time. The reason being that the time required to construct a project to mitigate the issues can take several years. This is due to the need for public input, permitting, acquisition, and construction. Attachment I does not allow planners to design temporary mitigation to accommodate real world construction issues, which are often complex in nature due to competing interests. Attachment I also states that “Before a Firm Demand interruption under footnote ‘b’ is allowed to be utilized as an element of a Corrective Action Plan in Year One of the Planning Assessment…” The need for approval seems burdensome such that it does not allow for temporary mitigation to meet BES performance criterion while other avenues are explored and vetted. The intent

of Section III is genuine, but we feel that it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to approval of the use of Firm Demand interruption under footnote ‘b’. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load.
The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2. Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV in P1 is of no value. The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 3 The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column.
Group
Arizona Public Service Company
Janet Smith
Arizona Public Service Company
Yes
Yes
Yes
No
AZPS does not agree that approval by the Regional Entity should be required. Once the process has been fully vetted by the stakeholders, including the regulatory authority for retail service, there is absolutely no need for Regional Entity approval. There would be no adverse affect of non-consequential load tripping on the BES. No reason for Reginal Entity involvement.
This process is too prescriptive and must be simplified.
Individual
John Martinsen
Public Utility District No. 1 of Snohomish County
No
No
No
No
Comments: SNPD generally disagrees with the draft process that has been developed, and notes that infrequent interruption of small amounts of non-consequential load under limited conditions that does

not negatively impact a neighboring TOP is not a reliability issue. Instead it is a cost of service and customer service matter best left to the local and state regulatory bodies. The time and resources spent on this issue at the national level diverts scarse resources and attention from more important efforts that might actually benefit the reliability of the BES. SNPD supports the Pacificorp Revision of TPL-002 footnote 'b' and TPL-001 footnote 1 Comments- The proposed revisions will require regulatory approval for interruptions of firm demand under TPL-002 footnote b or TPL-001 footnote 12 if the voltage level of the contingency is greater than 300 kV with certain sub-conditions or if the planned interruption of firm demand under these footnotes is greater than or equal to 25 MW. The 2011 peak winter and summer loads in the Western Electricity Coordinating Council (WECC) region were 131,471 and 152,211 MW respectively. Total installed generation is 229,189 MW. There are 120,385 miles of AC transmission lines 100 kV and above, and of that total, 31,138 miles of AC transmission lines are operated at voltages above 300 kV. There are 1,744 miles of DC transmission lines. The proposed revisions would add considerable process and documentation for any interruptions, and will require regulatory approval if the interruption is greater than 25 MW. This is 0.016 percent of the WECC peak load. The planning standards already require Category B1 contingencies to be considered which result in the loss of a single generator since individual generator units range in size up to more than 1000 MW. Since these contingencies are routinely studied, it is very, very difficult to imagine that the loss of 25 MW or more of firm demand under TPL-002 footnote b or TPL-001 footnote 12 is so critical to the reliability of the BES that it deserves not only a lengthy footnote, but a two page attachment detailing a complex and lengthy process detailing requirements public meetings, procedures for questions, specifications for documentation, and even a dispute resolution process. As this is not a BES reliability issue, any action regarding potential curtailments of local loads should occur at the local level where the cost and benefit of improvements can be properly assessed. The recent blackout that left 2.7 million customers in Southern California, Arizona and Baja California without power was not due to planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. SNPD is not aware of any regional disturbances or cascading events that were due to planned or controlled interruptions of electric supply where a single contingency occurred on a transmission system. As these proposed requirements could be removed from the Reliability Standards with little or no effect on reliability and would, if anything, increase the efficiency of the ERO compliance program, the proposed limitations on curtailment of firm demand under TPL-002 footnote b or TPL-001 footnote 12 should be removed.
Individual
Robert W. Creighton
Nova Scotia Power
Yes
Yes
Yes
Yes
With regard to the application of Footnote 12 in TPL-001-3, the footnote is only applied to the contingencies in Table 1 involving loss of a Single Line with a 3 phase fault (P1) or opening of a line without a fault (P2-1). These are higher probability events relative to other types of contingencies, and Footnote 12 allows for loss of load for these events, but does not allow for loss of load for lower probability events that have the same results, such as P2-2 and P2-3. Take for example a single radial 345kV line feeding a small radial portion of the system, with a line end transformer and breaker between the transformer and the line. Application of Footnote 12 to only a P1 event (loss of the line on its own, or loss of the transformer on its own) but loss of the breaker between the line and the transformer would not be allowed, even though the result would be the same. Without applying footnote 12 to category P2-2 and P2-3 would mean that Footnote 12 is rendered moot (can never be used). Similarly, Footnote 12 should be applied to P4 and P5, essentially wherever Footnote 9 is applied, otherwise Footnote 12 can never be applied.
Individual

Greg Rowland
Duke Energy
Yes
Situations where use of footnote ‘b’ would be appropriate can’t be readily characterized with criteria leading to some “technically justified” maximum capacity threshold for interruption. That being the case, a maximum capacity threshold could be established based upon other criteria, such as the 300 megawatt threshold for DOE disturbance reporting.
No
Since item 2 describes the public notice that must be provided, the phrasing of 2.b should be revised to replace the words “Specific applications” with the words “Summary description”. “Specific applications” could be considered to require detailed descriptions of each and every contingency that could lead to use of footnote ’b’. That level of detail could certainly be provided to meeting participants, but shouldn’t be necessary for the public notice.
No
In Item #8, replace the word “planners” with the words “Transmission Planners”.
No
Section III is confusing. Are the last two paragraphs of Attachment 1 supposed to be part of Section III? These paragraphs, when read in combination with the first paragraph of Attachment 1, seem to say that any time a Firm Demand interruption using footnote ‘b’ or footnote 12 shows up in the Near-Term Transmission Planning Horizon, the Stakeholder Process must be invoked. It would seem more reasonable to invoke the Stakeholder Process only when such interruption occurs in Year One of the Planning Assessment.
Individual
Chris de Graffenried
Consolidate Edison Co. of NY, Inc.
No
See reply to Question 5
No
See reply to Question 5
No
See reply to Question 5
No
See reply to Question 5
Planned interruptions of Firm Demand in response to a Single Contingency (as directed in Footnote b of TPL-002 Table 1, is not an acceptable corrective action to mitigate reliability issues on the BES system. The Interconnected System should be designed and operated with enough transfer capacity to be able to withstand, at a minimum, a single contingency event without service interruptions to customer load. Systems must be designed and operated so that the impact of any single contingency can be mitigated by re-dispatching available system resources without the need to implement load shedding.
Individual
Charlie Pottey
Sierra Pacific Power Co d/b/a NV Energy
Individual
Richard Vine
California Independent System Operator
No
We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest deleting this sentence. Assigning a fixed “not to exceed” number of MW in a continent-wide standard is overly prescriptive. A single number

cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others. A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, “[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events”. It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fix maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving “safe harbor” to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the “not to exceed” amount. We support the description and components of the Stakeholder Process in the body of the footnote, but do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability, as explained above. Also, we have comments on the reference to Attachment I. Please see our comments under Q5.
No
The process presented in Section I of Attachment I is overly prescriptive. Identifying the need for stakeholder consultation on this issue within the consultation process already employed by the Transmission Planner or Planning Coordinator should be sufficient detail. In particular, however, we suggest removing item 5, “A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction”. Given that the “applicable regulatory authorities or governing bodies responsible for retail electric service issues” are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution? There is no basis to support only allowing the utilization of the footnote in the Near-Term Transmission Planning Horizon of the Planning Assessment. The footnote itself leaves the time frame wide open, and does not explicitly or implicitly restrict its utilization to only the Near-Term horizon. Often, in the long-term planning horizon, when approval for transmission addition or reinforcement cannot be obtained for whatever reasons, utilization of the footnote is considered. Note that it is impractical to add or reinforce transmission facilities in a near-term planning (e.g. Year 0ne) time frame and hence the proposed provision does not allow for utilizing the footnote for the interim period before new or reinforced transmission facilities are put in place. We suggest removing the word “Near-Term”.
No
This Section is overly prescriptive. This Section needs only to stipulate at a high level, the kind of information needed to support the proposed utilization of footnote b and footnote 12. In particular, we disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the “applicable regulatory authorities or governing bodies responsible for retail electric service issues”.
No
We do not agree with the requirement to seek regulatory authority approval or Regional Entity approval. Having this requirement in a reliability standard not only is unnecessary, but also introduces regulatory requirements (which provide no reliability benefit or basis) in a reliability standard. NERC reliability standards should focus only on BES reliability, not on any regulatory requirements. A notification process should be sufficient. It is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues for approval of the use of Firm Demand interruption under footnote ‘b’. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As

stated in this questionnaire, 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It would be a stretch to apply this to load. Requiring the Regional Entity to approve the Non-Consequential Load Loss under footnote b in TPL-002 (Footnote 12 in TPL-001-3) would be duplicative and would increase the work load of the Regional Entities without improving reliability. The TP and PC are already required to make available to the affected stakeholders, verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’ (see Section II.6) and the assessment of potential overlapping uses of footnote ‘b’ with adjacent planners” (see Section II.8). What type of review and verification would be required to show that “there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity’s footprint”?
The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2. Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV in P1 is of no value. The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 3 The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column. The process described in Attachment 1 may be more suited for inclusion in the Rules of Procedure, similar to the process required for seeking BES facility exceptions. We urge the SDT to consider moving Attachment 1 into a proposed RoP instead of stipulating it in the standard.
Individual
charlie pottey
nevada power company dba nvenergy
No
We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest deleting this sentence. Assigning a fixed “not to exceed” number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others. A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, “[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events”. It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fix maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving “safe harbor” to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the “not to exceed” amount.
No
We suggest removing item 5, “A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction”. Given that the “applicable regulatory authorities or governing bodies responsible for retail electric service issues” are only one of the many

affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?
No
We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the "applicable regulatory authorities or governing bodies responsible for retail electric service issues".
No
While we do not disagree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to approval of the use of Firm Demand interruption under footnote 'b'. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load. Requiring the Regional Entity to approve the Non-Consequential Load Loss under footnote b in TPL-002 (Footnote 12 in TPL-001-3) is duplicative and would increase the work load of the Regional Entities without improving reliability. The TP and PC are already required to make available to the affected stakeholders, verification that TPL Reliability Standards performance requirements will be met following the application of footnote 'b' (see Section II.6) and the assessment of potential overlapping uses of footnote 'b' with adjacent planners" (see Section II.8), it is hard to imagine what type of review and verification is required to show that "there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity's footprint".
The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2. Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV in P1 is of no value. The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 3 The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column.
Group
Western Area Power Administration
Brandy A. Dunn
Western Area Power Administration (Corp. Services Office)
No
The addition of the "Stakeholder Process" outlines in Attachment 1 is so onerous so as to persuade entities NOT to attempt the use of Footnote b) OR 12). Is this the intent?

Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
No
Comments: It is difficult to establish the maximum value for acceptable Firm Demand interruption. For example, an entity may have an acceptable maximum load loss to avoid impacts on the grid such as generation trip-outs. For Hydro-Québec TransÉnergie (HQT), in the Québec Interconnection, this value is above 1,000 MW. No maximum value should be posted in Footnotes 12 and 'b', since it is specifically related to system design and Interconnection size (inertia). Let us keep in mind that the goal of the TPL standards is not service continuity of local loads but global reliability of the system. Even though service continuity is important, TPL standards should not address this issue by posting a maximum allowable load loss. Moreover, HQT considers that a Stakeholder Process such as seen in Attachment I has no place in a standard and its footnotes. Mainly, the Stakeholder Process doesn't consider that entities may have their own regulatory authorities with different processes, which do not specifically establish this load loss value.
No
The Stakeholder Process doesn't consider that entities may have their own regulatory authorities with different processes, which do not specifically establish load loss values. Also, the use of Firm Demand interruption in the Corrective Plan should not be limited only to the Near-Term Transmission Planning Horizon. It should also be allowed for the Long-Term horizon, at least for Multiple Contingencies.
No
For example, under 2 b., assessment of the impacts of interruptions on health, safety, or welfare of the community is not information that could be reasonably expected to be available to system planners. All loads may face interruptions from time to time, and the impact on health, safety or welfare is very difficult to identify. This item should be deleted.
No
For example, in 1a., it is not clear what is meant by "the stated performance criteria regarding allowances...". Why is it necessary to give this kind of explanation? In 1b., the use of the term "non-generator step up transformer" is unusual. Suggest rewording 1b to read: For a generator or generator step up transformer outage Contingency, the extra high voltage (EHV) limit applies to the BES connected voltage (high-side of the Generator Step Up transformer). For any other transformer outage Contingency, the EHV limit applies to the low-side winding (excluding tertiary windings).
Footnote 12 is not applied to Categories P4 and P5, which would include a EHV stuck breaker or failure of a non-redundant relay for a Multiple Contingency. The Load loss restriction for the contingencies listed in P4 and P5 is more restrictive than for the loss of a EHV double circuit line. Statistics indicate that the contingencies presented in P4 and P5 are less frequent. HQT requests that Footnote 12 should also be used for P4 and P5 contingencies for EHV. Even though considering Firm Demand interruption in planning might not be common practice, HQT agrees that the proposed Footnote 12 should maintain such a possibility.
Individual
Chris Scanlon
Exelon
No
For TPL-001, the wording for footnote 12 does not make clear that DSM would be allowed without the Attachment 1 procedure. ComEd suggests the following wording change: 12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to ensure that BES performance requirements are met. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements (other than Interruptible or Demand Side Management load), such interruption is limited to circumstances where the Non-Consequential Load Loss is meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 12 exceed 'x' MW. For TPL-002, the wording of

footnote “b” is not totally clear that it applies only to non-consequential load shed and not consequential load shed. ComEd suggests that the wording of footnote “b” be changed as shown: b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner’s planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to ensure that BES performance requirements are met. When interruption of Firm Demand (other than in (1) or (2) above) is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote ‘b’ exceed ‘x’ MW.
Individual
Catherine Mathews
NorthWestern Energy (NWMT)
No
Comments: A fixed maximum number of MW for Non-Consequential Load Loss should not be used in an industry-wide standard. There is too much diversity. We suggest that a fixed maximum number not be stipulated.
No
Comments: It is unclear how the dispute resolution process would treat stakeholders with different concerns. We suggest that Item 5 of Attachment 1 be deleted.
No
Comments: The estimated number and type of customers affected is not needed for reliability of the Bulk Power System. We suggest removing Item 2a in Section II of Attachment 1. An assessment of the health, safety, and welfare of the community should not be required. It is too vague and coud present legal problems. We suggest removing Item 2b in Section II of Attachment 1.
No
Comments: A NERC Standard should not require action from a regulatory authority to approve the use of Firm Demand interruption. There is too much diversity in regulatory authorities over the industry-wide area. This would increase the work load of the Regional Entities without improving reliability. We suggest removing Section III of Attachment 1.
Comments: Footnote 12 should be added to Category P2 Single Contingency Event 2, Bus Section Fault, and to Category P2 Single Continency Event 3, Internal Breaker Fault , for EHV in the Non-Consequential Load Loss column.
Individual
Robert Casey
Georgia Transmission Corporation
Yes
Please remove the “is” as shown below: “12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to ensure that BES performance requirements are met. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss [IS] meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 12 exceed ‘x’ MW.”

No
Item #1 in Section I should be reworded: From This....“Meetings must be open to all affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues.” Reworded to say: “Meetings must be open to all affected NERC Registered Entities including applicable regulatory authorities or governing bodies responsible for retail electric service issues.” The concern is that stakeholders could be too broadly construed including residential, commercial, industrial customers, and even more so (i.e transitory customers). We recommend that the sentence be reworded as shown above. Additionally, GTC request feedback from the SDT's intent. Is a stakeholder meeting required every year a planning assessment is done showing that non-consequential load loss is required?
No
GTC does not understand how item #2b of Section II pertains to the Transmission Planner or the Planning Coordinator. These types of assessments are beyond the scope of the Transmission Planner or the Planning Coordinator and if necessary, should possibly be done by the Load Serving Entity. GTC Recommends the SDT remove item #2b, the following sentence: “An assessment of the use of Firm Demand interruption under footnote 12 on the health, safety, and welfare of the community.”
No
GTC would appreciate if the SDT could please clarify if the approval of a regulatory authority or governing body is referring to the Regional Entity. The first sentence in Section III: “Approval of the use of Firm Demand interruption under footnote 12 by the applicable regulatory authority or governing body responsible for retail electric service issues is required if either:...”
The current draft for Requirement 5 (R5) of the NERC Standard TPL-001-3 Draft 1 reads as follows: “Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.” GTC has the following comments regarding TPL-001-3, R5: If the responsible entity has criteria for transient voltage response, along with criteria for acceptable system steady state voltage (including a pre-contingency high and low voltage limit, and a post-contingency high and low voltage limit), then having a steady state post-contingency voltage deviation criteria does not affect the reliability of the bulk electric system (BES). If the system response to a disturbance were to violate either the transient response criteria, or the steady state maximum/minimum voltage criteria, there is potential for loss of integrity of the BES. There is little to no potential for a loss of system integrity due soley to a violation of the steady state voltage deviation criteria. Therefore, Georgia Transmission Corporation requests that R5 not include a requirement to have criteria for post-Contingency voltage deviations.
Individual
Kathleen Goodman
ISO New England Inc.
No
For single contingency events, footnote 12 should be eliminated. Planning the electric system for non-consequential load loss as a means to address a single contingency should not be acceptable. If the footnote is to remain, as a minimum the attachment should be changed to increase the emphasis on the near term nature of the use of non-consequential load shedding.
No
With regard to Section I, in paragraph I.5, the stakeholder process includes a dispute resolution process. Existing ISO/RTO stakeholder processes are FERC approved and rigorous, requiring a dispute resolution process goes beyond the existing requirements in ISO/RTO tariffs. Item I.5 should be eliminated.
No
Section II, Paragraph 2b requires “an assessment of the use of Firm Demand interruption under footnote 12 on the health, safety, and welfare of the community”. A great deal of subjectivity and information that is not readily available to the Transmission Planner or Planning Coordinator would be required to accurately access the effect of load shedding on the community as required by 2b. Additionally Paragraphs II.3 and 4 require estimates of the frequency and duration of Firm Demand interruption would be difficult to provide. These requirements should be deleted. These requirements

also undermine the deterministic nature of the Planning Standard. Paragraph II.2.5 that requires future plans to mitigate the need for Firm Demand Interruption should be modified to again emphasize the near term nature of single contingency non-consequential load shedding as a Planning option.
No
Section III describes the instances where Approval of Interruptions of Firm Demand are required under footnote 12. It is not clear whether under Paragraph III.1.a and Paragraph III.1.b the Transmission Planner is to base the determination on either contingency or both contingencies i.e. is "and" logic to be applied or is "or" logic used? Paragraph III.2 requires such approval for interruption equal to or greater than 25 MW, this is a very small amount of load to be required to bring to a stakeholder approval process for second contingency events. This amount should be increased to at least 100 MW. Additionally in Section III, it is not clear who the "regulatory authority or governing body responsible for retail electric service issues" is. Having this requirement in a reliability standard not only is unnecessary, but also introduces regulatory requirements in a reliability standard. NERC reliability standards should focus only on BES reliability, not any regulatory requirements. The Attachment goes on to state "The Regional Entity determinations of Adverse Reliability Impacts are to be evaluated by the Regional Entity through a published methodology approved by the ERO". This is essentially a "fill in the blank" requirement and makes it necessary to comment and approve the footnote attachment without the benefit of reviewing a proposed methodology.
Individual
Bangalore Vijayraghavan
PG&E Company
No
We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest deleting this sentence. Assigning a fixed "not to exceed" number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others. A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, "[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events". It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fix maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving "safe harbor" to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the "not to exceed" amount.
No
We suggest removing item 5, "A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction". Given that the "applicable regulatory authorities or governing bodies responsible for retail electric service issues" are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?
No
We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision

by the “applicable regulatory authorities or governing bodies responsible for retail electric service issues”.
No
While we do not disagree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to approval of the use of Firm Demand interruption under footnote ‘b’. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load. Requiring the Regional Entity to approve the Non-Consequential Load Loss under footnote b in TPL-002 (Footnote 12 in TPL-001-3) is duplicative and would increase the work load of the Regional Entities without improving reliability. The TP and PC are already required to make available to the affected stakeholders, verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’ (see Section II.6) and the assessment of potential overlapping uses of footnote ‘b’ with adjacent planners” (see Section II.8), it is hard to imagine what type of review and verification is required to show that “there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity’s footprint”.
The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2. Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV in P1 is of no value. The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 3 The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
No
SCE&G does not agree with the proposed modifications to footnote b. SCE&G believes the original footnote b is appropriate and consistent with the Energy Policy Act of 2005. SCE&G cites several statements in the Energy Policy Act of 2005 as justification for our position. 1. The Energy Policy Act of 2005 states: “The term ‘reliability standard’ means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity." It also states, “This section does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services.” SCE&G believes the proposed modifications to footnote b will result in building or enlarging facilities to meet the proposed requirements. Also, any requirement that disallows load interruption or limits the amount of load interruption infringes on the stated limitation on the ERO to not set and enforce compliance with standards for adequacy. 2. It also states: The term ‘reliable operation’ means operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits

so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements." In this statement there is no mention of disallowing the interruption of firm load. It only requires that instability, uncontrolled separation, or cascading failures not occur. SCE&G believes the proposed changes to footnote b are beyond the authority granted to the ERO by the Energy Policy Act. 3. It also states: ''Nothing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard, ..." SCE&G believes the proposed modifications to footnote b infringe on the state's authority to address adequacy and reliability of electric service within the State.
No
See response to question #1
No
See response to question #1
No
See response to question #1
none
Group
ACES Power Member Standards Collaborators
Jason Marshall
ACES Power Marketing
No
We disagree with placing an upper limit on the amount of firm load shed. Conceptually, it seems like a good idea but we do not believe that such a threshold could ever consider all of the potential issues that could arise and would cause the need to plan to shed firm load. This is especially true considering that the SAR clarifies that the upper threshold will be based on the existing planned load shedding values. Future issues cannot be considered by such a data request. Consider a situation in which a new transmission line was included in Planning Assessment but cannot be built because right of ways cannot be obtained. Should an upper limit be placed on planned load shed in such a situation?
No
(1) Attachment 1 should clarify that it only applies when approval is not required by the regulatory body with authority over retail service, such as local regulatory authorities and state public utility commissions. This includes whether the approval is required by NERC rules or another regulatory body's rules. It does not make sense for the Transmission Planner or Planning Coordinator to duplicate a process that is already required by another regulatory body that satisfies due process. As an example, why should the Transmission Planner and Planning Coordinator have a dispute resolution process if the regulatory body already has a dispute resolution process that can be used. It also does not make sense for the Transmission Planner and Planning Coordinator to be compelled to have a stakeholder comment process when the local regulatory body's approval is required. Having such a process is duplicative and unnecessary. (2) Many RTOs have well organized stakeholder processes that could be utilized to satisfy Attachment I. Because the TPL standards apply to both the PC and TP, one may believe the both the PC and TP need to have these stakeholder processes. Rather, we think that the TP should be able to rely on its PC's stakeholder process. We suggest Attachment I should clarify that this is acceptable and that both entities are not required to have redundant processes. The most important point is that stakeholders have an opportunity to participate.
No
(1) We disagree with with including the Facilities that will exceed their rating and the applicable contingenices. We think this information should be treated as confidential. It could be used by bad actors to create outages within communities. The risk to the Bulk Electric System is higher than the benefit of sharing this information. (2) We disagree that the Transmission Planner should be required to provide an assessment on the health, safety and welfare of the community. First, the stakeholders will have an opportunity to provide this information through either the Transmission Planner's stakeholder comment process or through the local regulatory agency's stakeholder comment process. Second, these planned interruptions in firm demand are expected to be short in nature so the impacts

should be minimal. Third, an assessment on the health, safety and welfare of the community is an unnecessary burden on the utility and is better suited for local governments. Even if the utility should perform such an assessment, health, safety and welfare are ambiguous terms without clear parameters or expectations for the data. Does this mean that the Transmission Planner verifies police stations, fire departments, hospitals and other critical public support agencies are not included in the planned load shed? Most electric providers already do this when developing load shed plans and are likely not going to includes such customers in any load shed plan. Fourth, communities already have plans in place for the interruption of electricity so as long a critical customers are not shed, then the impacts are likely economic in nature. (3) Bullet 3 needs to be clarified that it is not an estimated frequency but rather a historical frequency. How do you estimate a frequency for a new planned load shed? It also needs to be clarified if the historical frequency is all instances within the Transmision Planner's area or just the specific location of the planned load shed. If it is all instances, it further needs to be clarified that it is only within its own TP area. (4) We do not believe that expected duration of the planned load shed should be required. Any duration will likely be a guess. When actual contingencies occur, the time of restoration varies. Consider the recent event in Arizona and Southern California. The report indicated that the TOP thought they could return the 500 kV line that initiated the event in a few minutes. They were unaware that the phase angle was too large to close. The expected duration is too speculative and should not be required. (5) We disagree with the need to include future plans to mitigate the planned load shed in all cases. For remote areas of the system, there simply may not be sufficient load growth to justify any other mitigation. (6) Item 8 should be clarified that it applies only to the Planning Coordinator. The Planning Coordinator should coordinate all of its Transmission Planner's Planning Assessments. This would include evaluating planned load shedding.
No
(1) What is the justification for selecting a 300 kV contingency as a threshold for requiring local regulatory agency approval? What if the planned load shed is only for 1 MW? If a threshold is required, we think it should be based on load size rather than contingency size? (2) What is the justification for selecting 25 MW of planned firm load interruption as a threshold for requiring local regulatory approval? The threshold could be set based off of the accompanying Section 1600 data request. Since there are likely not many instances, it could be required for any new instance that exceeds the existing planned load shed amounts. Thus, the threshold would be set just above existing planned load interruptions. (3) A disclaimer should be added to clarify that an entity may still have to seek local regulatory agency approval per the local regulatory agency's rules. Nothing in the NERC standard will change the local regulatory agency's rules. (4) What if the local regulatory agency does not want to address the planned load shed in the planning time frame? What is the Transmision Planner required to do? While it is likely a local regulatory agency would be interested in addressing a planned load interruption, nothing in the NERC or Commission rules can compel a local regulatory agency to address such matters in a specific time frame. (5) Bullet 1.a is confusing. Is it intended to say that if two Elements are part of a contingency and the Elements have different voltage classes, the Element with the lowest voltage class must exceed the 300 kV threshold? If this is the case, the bullet needs further clarification because it does not state this clearly. (6) The first paragraph after section III appears to contradict bullets 1 and 2. Bullets 1 and 2 place contingency and load thresholds on the planned firm load interruption. However, this paragraph says that the regulatoy body responsible for retail electric service must approve the planned load shed before it can be used in Year One of the planning assessment. If the purpose is for the thresholds to apply beyond Year One and any instance in Year One to require approval, then the language regarding the thresholds needs to clarify that the thresholds apply beyond Year One only. (7) We think it is redundant for the Regional Entity to evaluate planned interruptions of firm load in its footprint. The Planning Coordinator has a wide area view and is already required to do this for its footprint. The Planning Coordinator already works with its neighbors to evaluate impacts. Requiring this evaluation by the Regional Entities is arbitrarily based on historical and political boundaries. Many Planning Coordinators have views that are broader than the Regional Entity view because they are in multiple regions. If this evaluation will be required on a regional basis, why won't it be required on an interconnection? (8) The evaluation required by the Regional Entity may be completed before planned load interruption is approved by local regulatory body. The TP and PC must submit the data based on their plan before the local regulatory body approves the planned load interruption. The Regional Entity must complete its evaluation within 45 days of receiving the information. There is no obligation for the local regulatory body to act within 45 days. Wouldn't it make more sense to evaluate the planned load

shed after it is approved by the local regulatory body?
(1) The standard needs to allow more flexibility regarding the use of planned load shed to address transmission performance issues in the planning horizon. It needs to recognize that these planned load shedding events may only be preliminary decisions for addressing problems that are several years away. If there is little chance that the planned shed load will ever be relied upon in the operating time horizon, there should be much less stringent requirements. For instance, if a PC or TP relies on planned load shed for year five of the planning horizion but year one does not utilize the planned load shed, they have four years to develop another solution. Why should great effort and resources be expended in year five when another solution will likely be developed? (2) This standard does not consider if the local regulatory body will act in time to approve the use of planned Firm Demand interruption. We believe the standard needs to consider that the Planning Coordinator and Transmission Planner may not be able to control the timelines of local regulatory agencies. As long as the PC and TP have done their part by submitting the data, they should be able to rely on the planned Firm Demand interruption until the local regulatory body acts. If the planned Firm Demand interruption is not approved, then the TP and PC should be given more time to address the transmission performance deficiency. (3) Several terms are used for the use of planned load shed. Non-consequential load loss and Firm Demand interruption are two examples. We suggest using one term consistently throughout the standard.
Individual
Steve Myers
Electric Reliability Council of Texas, Inc.
No
As an initial matter, ERCOT does not believe the planning process should allow for non-consequential load shedding under single contingency conditions. However, if the SDT elects to retain a vehicle for such exceptions, it should establish objective, reliability based criteria that lend themselves to inclusion in a reliability standard. This is consistent with the general approach for reliability standards, which prescribe the “what”, not the “how”. If the exceptions are based on objective criteria that are known upfront, and those criteria reflect appropriate reliability based technical justifications, then the risk of unwarranted exceptions to the general prohibition due to misuse of the exception process is mitigated. Furthermore, the exception process should be external to the NERC Reliability Standards (e.g. in the Rules of Procedure), which should merely reference authorized exceptions granted pursuant to that process. In no case should a reliability standard mandate a stakeholder process in any respect, procedural or substantive. In ISO/RTO regions, stakeholder processes fall within ISO/RTO governance matters. These issues are beyond the purview of NERC Reliability Standards. In other regions, although the relevant functional entities do not have stakeholder processes analogous to ISOs/RTOs, any relevant processes are similarly beyond the scope of the reliability standards. Accordingly, the SDT should eliminate all revisions related to the establishment of a stakeholder process. As discussed in response to question 5, FERC is not requiring this approach, but rather has only provided guidance with respect to ways to possibly bring the prior proposal in line with applicable regulatory approval standards for reliability standards. Additionally, as a general matter, substantive reliability standards requirements should not be imbedded within a footnote to a requirement. In this case, not only is there a substantive requirement imbedded in the footnote, there is also a substantial attachment (which must become part of the enforceable standard requirements)…and, to make it worse, the attachment is an attachment to the footnote, rather than an attachment to and referred to by a reliability standard requirement.
No
Please see ERCOT’s response to Question 1.
No
Please see ERCOT’s response to question 1 – the NERC Reliability Standards should not contain requirements related to stakeholder processes, whether they are procedural or substantive. If an exception process is retained, it should be outside of the NERC Reliability Standards (e.g. in the Rules of Procedure). ERCOT also provides the following comments on Section II – the ERCOT comments are in parentheses for easy reference and distinction relative to the proposed requirements. II. Information for Inclusion in Item #3 of the Stakeholder Process The responsible entity shall document the planned use of Firm Demand interruption under footnote ‘b’ which must include the following: - (ERCOT COMMENT: This is all that is needed for this. The documentation would be relative to the

objective criteria developed for this purpose.) 1. Conditions under which Firm Demand interruption under footnote 'b' would be necessary: a. System Load level and estimated annual hours of exposure at or above that Load level b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency (ERCOT COMMENT: "1" is not necessary if objective criteria are developed as benchmarks for the exception process. In that case, exceptions would only be allowed if the objective criteria were met, regardless of the underlying assumptions related to conditions and contingencies.) 2. Amount of Firm Demand MW to be interrupted with: a. The estimated number and type of customers affected b. An assessment of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community (ERCOT COMMENT: The considerations reflected in a and b are inappropriate for a reliability standard. Appropriate considerations for reliability standards are related to the reliability performance of the system. The considerations in a and b are more akin to quality of service issues better suited for regional policy discussions. It is not within the purview of the SDT to address those matters.) 3. Estimated frequency of Firm Demand interruption under footnote 'b' based on historical performance (ERCOT COMMENT: Historical performance is irrelevant. If the SDT is going to retain revisions that accommodate non-consequential load shedding, then the only relevant metrics are the objective criteria that set the benchmarks for such exceptions.) 4. Expected duration of Firm Demand interruption under footnote 'b' based on historical performance (ERCOT COMMENT: See ERCOT response to "3" above.) 5. Future plans to mitigate the need for Firm Demand interruption under footnote 'b' (ERCOT COMMENT: This is redundant to the requirement in the reliability standards that requires a plan to resolve any violations identified in the planning process. Furthermore, if load shedding is allowed, this requirement doesn't make sense. Presumably the idea behind allowing these exceptions is to obviate the prospective need for other alternatives. If that is not the case, then there is no need to allow the exceptions, because the transmission upgrades to mitigate the need for load shedding can be established in the planning horizon.) 6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 'b' (ERCOT COMMENT: The basis for the load shedding exception is to provide a means to meet the TPL performance requirements in the context of a planning assessment. Accordingly, this is redundant to the planning assessments, the point of whichis to identify and resolve performance issues.) 7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote 'b' (ERCOT COMMENT: Load shedding exceptions should be based on objective criteria and be reviewed pursuant to a process external to the NERC reliability standards. Alternative discussions could be part of that external process.) 8. Assessment of potential overlapping uses of footnote 'b' with adjacent planners (ERCOT COMMENT: It is not clear what this means. Each functional entity performs assessments relative to its own system. This appears to introduce a vague regional transmission planning requirement with no structure or rules for such assessments.)
No
If non-consequential load shedding is allowed for single contingency conditions, as discussed above, it should be based on objective critieria. As such, there is no need for the proposed stakeholder process, including the Section III instances requiring regulatory approval. As with the other stakeholder process sections, that section should be eliminated.
The SDT is not required to utilize the stakeholder approach by Order 762 or any other relevant FERC orders. FERC merely provided guidance as to how the rejected proposal could be improved. However, if the SDT elects to pursue an exception process, such exceptions should be based on objective criteria, and the process should be external to the NERC Reliability Standards (e.g. in the Rules of Procedure). In Order 693, FERC directed NERC to clarify footnote (b) to prohibit shedding firm load except for consequential load loss (Order 693 at PP 1773, 1794 and 1797). In a related compliance order, FERC reaffirmed its position. (130 FERC ¶ 61,200 (March 18, 2010) at PP 8-10 (Compliance Order)) In a subsequent order, FERC clarified that its Order 693 directive did not preclude consideration of specific comments related to planning the system based on load shedding at the "fringes" of a system. (131 FERC ¶ 61,231 (June 11, 2010) at P 21 (Clarification Order)) FERC held that regional variances for case-specific circumstances or a case-specific exception process to plan for the loss of firm service "at the fringes of various systems" would be acceptable. (131 FERC ¶ 61,231 (June 11, 2010) at P 21 (Clarification Order)) However, FERC also stated that it viewed the basis for such exceptions as economic, not reliability, with the justification being that it was not economic to invest in the bulk electric system to serve all non-consequential load customers under some single contingency conditions. (Order 693 at P 1792) FERC made clear that any such regional differences or

case specific exception processes cannot reflect the lowest common denominator, and, they must be technically justified, and such justification must be strong. (Clarification Order at P 21. See also Order 693 at P 1794) This is consistent with FERC's position that this is a matter of "fundamental issue of transmission service". (Order 693 at P 1793) In recognizing that meeting firm demand under single contingency conditions is fundamental to transmission service, FERC noted that NERC's definition of firm transmission service is the "highest quality (priority) service offered to customers...that anticipates no planned interruption." (Order 693 at P 1793) Against this background, NERC filed revisions to footnote b that allowed transmission plans to shed non-consequential load under single contingency conditions, provided appropriate process applied to such planning determinations/outcomes. In Order No. 762, (139 FERC ¶ 61,060 (April 19, 2012)) FERC rejected the approach proposed by NERC and provided guidance on acceptable approaches to footnote b. However, FERC did not endorse or mandate any particular approach. Rather, it merely urged "NERC to develop in a timely manner an appropriate modification that is responsive to the Commission's directives in Order No. 693 and our concerns set forth in this Final Rule." (Order 762 at P21) FERC stated that in order for any such proposal to have merit, it must be technically justified and must not reflect the lowest common denominator. As discussed, the proposed stakeholder approach is not appropriate for NERC Reliability Standards. The SDT should abandon that approach and consider simple revisions to footnote b that reference a case by case exception process based on objective criteria that is external to the NERC Reliability Standards (e.g. Rules of Procedure). Alterantively, it should develop revisions to the continent-wide standards that clarify that non-consequential load shedding is not generally permitted for single contingency conditions, but, consistent with FERC's orders, exceptions could be established pursuant to regional rules based on the need/appropriateness in a particular region. Consistent with the above discussion, if the SDT elects to pursue revisions that accommodate shedding non-consequential load in transmission planning for single contingency conditions, it should abandon the stakeholder process approach. The establishment of exceptions is better suited for regional rules or pursuant to a process outside of the reliability standards – e.g. via the Rules of Procedure, because such a process is not suited for a continent-wide reliability standard. Regardless of whether the issue is addressed via an external process, or left to regional variances, this issue needs to be addressed in a relatively timely manner because the uncertainty is affecting planning processes.
Individual
Ed O'Brien
Modesto Irrigation Districtt
No
We do not agree with the concept of non-consequential load loss in light of historic application of N-1 criteria, that only provides for consequntial load loss.
No
We suggest removing item 5, "A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction". Given that the "applicable regulatory authorities or governing bodies responsible for retail electric service issues" are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?
No
We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the "applicable regulatory authorities or governing bodies responsible for retail electric service issues".
No
While we do not disagree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues

to approval of the use of Firm Demand interruption under footnote ‘b’. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load. Requiring the Regional Entity to approve the Non-Consequential Load Loss under footnote b in TPL-002 (Footnote 12 in TPL-001-3) is duplicative and would increase the work load of the Regional Entities without improving reliability. The TP and PC are already required to make available to the affected stakeholders, verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’ (see Section II.6) and the assessment of potential overlapping uses of footnote ‘b’ with adjacent planners” (see Section II.8), it is hard to imagine what type of review and verification is required to show that “there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity’s footprint”.
Group
Bonneville Power Administration
Chris Higgins
Transmission Reliability Program
No
BPA does not support quantitative limits on planned interruption, as planners generally do not plan the system to interrupt demand for a single contingency. As stated in the proposed footnote b, “[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events.” Setting a quantitative limit would push transmission planners to plan the system to meet such a limit for a single contingency in all cases. Moreover, a quantitative limit would be difficult to implement due to the wide variety of system configurations and conditions. BPA believes an appropriate amount would be dependent on the topography and the size of the system being planned.
No
Regarding the stakeholder process and dispute resolution, BPA believes that a decision for Firm Demand interruption needs to be made based on what is best for the system, not a specific dispute resolution process.
No
BPA does not support including information under Sections II.2.a and II.2.b, estimated number and type of customers affected, or an assessment of the use of Firm Demand interruption on the health, safety, and welfare of the community as this information does not support reliability of the BES. If footnote b were applied, reliability of the BES is actually assessed by meeting the applicable TPL Standard for a single contingency with loss of load regardless of the type of customers or use of Firm Demand.
No
Regarding Section III.2 as stated above, BPA does not support quantitative limits on planned interruption, as planners generally do not plan the system to interrupt demand for a single contingency. Setting a quantitative limit would push transmission planners to plan the system to meet such a limit for a single contingency in all cases.
Individual
R. Peter Mackin
Utility System Efficiencies, Inc.
No
We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest deleting this sentence. Assigning a fixed “not to exceed” number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others. A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of

this footnote states, "[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events". It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fix maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving "safe harbor" to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the "not to exceed" amount.
No
We suggest removing item 5, "A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction". Given that the "applicable regulatory authorities or governing bodies responsible for retail electric service issues" are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?
No
We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which makes compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the "applicable regulatory authorities or governing bodies responsible for retail electric service issues".
No
While we do not disagree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to approval of the use of Firm Demand interruption under footnote 'b'. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this value to load. Requiring the Regional Entity to approve the Non-Consequential Load Loss under footnote b in TPL-002 (Footnote 12 in TPL-001-3) is duplicative and would increase the work load of the Regional Entities without improving reliability. The TP and PC are already required to make available to the affected stakeholders, verification that TPL Reliability Standards performance requirements will be met following the application of footnote 'b' (see Section II.6) and the assessment of potential overlapping uses of footnote 'b' with adjacent planners" (see Section II.8), it is hard to imagine what type of review and verification is required to show that "there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity's footprint".
The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2. Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV is inconsistent with P1. The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of

footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 2 The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column. The new definition of Non-consequential Load Loss compared to the last version seems to have deleted the reference to Loads that may be lost during transient conditions due to under-frequency load shedding (UFLS), while the reference to Load Loss due to under-voltage load shedding (UVLS) is retained. As a result Load Loss due to UFLS would be part of Non-consequential Load Loss, and will not be allowed under single contingency. Because UFLS may also be triggered during transient simulations, please change the definition for Non-consequential Load Loss to read: "Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load or frequency sensitive Load, or (3) Load that is disconnected from the System by end-user equipment." It is also understood that load loss due to UVLS or UFLS or load that are disconnected from the system by customer equipment are not to be used in meeting steady state reliability requirements. Therefore, in Table 1, please change header-note "i" to read: "The response of voltage sensitive Load and Frequency sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements."

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

TPL Table 1 Order – Project 2010-11

The TPL Table 1 Order Drafting Team thanks all commenters who submitted comments on the revision of TPL-002 footnote 'b' and TPL-001 footnote 12. These standards were posted for a 30-day public comment period from July 31, 2012 through August 29, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 51 sets of comments, including comments from approximately 117 different people from approximately 81 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

Due to comments received, the SDT has made the following changes to the text:

- Effective date – updated to latest approved language
- Main footnote
  - Grammatical change from 'should be' the intent to 'is' the intent.
  - Clarified the near-term and long-term requirements.
  - Defined the ceiling threshold as 75 MW.
- Attachment 1
  - Section I
    - Clarified that an existing process can be utilized, as long as it meets the criterion in Section I.
    - Changed 'all affected stakeholders' to 'affected stakeholders'.
    - Changed 'specific applications' to 'specific locations'.
    - Added statement that says that the process does not have to be repeated in subsequent years if conditions haven't changed.
  - Section II
    - Item 2.b has been clarified to better show the SDT's intent.
    - Item 8 has been changed from 'planners' to 'Transmission Planners and Planning Coordinators and clarified to indicate that it includes both the local and adjacent entities.
  - Section III
    - Clarified role of regulatory authority.
    - Deleted role of Regional Entity.
    - Defined the ceiling threshold as 75 MW.
- Footnote 12 only – Corrected terminology to use 'Non-Consequential Load loss' instead of 'Firm Demand interruption'.

The SDT is requesting that this project be moved forward to the initial ballot and comment phase of the process.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Sunitha Kothapalli	Puget Sound Energy	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joseph (Joe) W Seabrook	Transmission Contracts	WECC	1, 3, 5
2.	Peter (Pete) M Jones	Transmission Contracts	WECC	1, 3, 5
3.	Kebede Jimma	Transmission Planning	WECC	1, 3, 5
4.	Gary Shumate	Transmission Planning	WECC	1, 3, 5
5.	Harris Wayne	Transmission Planning	WECC	1, 3, 5
6.	Carol Jaeger	Transmission Planning	WECC	1, 3, 5
7.	Zachery (Zach) Sanford	Transmission Planning	WECC	1, 3, 5
8.	Eleanor Ewry	Transmission Planning	WECC	1, 3, 5

2.	Group	Guy Zito	Northeast Power Coordinating Council										X

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael R. Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Team	X	X	X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	Robert Rhodes	Southwest Power Pool	SPP	NA
	John Allen	City Utilities of Springfield	SPP	1, 4
4.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
5.	Harold Wyble	Kansas City Power and Light Company	SPP	1, 3, 5, 6
6.	Katy Onnen	Kansas City Power and Light Company	SPP	1, 3, 5, 6
7.	Don Taylor	Westar	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Bob Steiger	Salt River Project	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brian Keel	SRP	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.	CHUCK LAWRENCE	ATC	MRO	1
3.	TOM BREENE	WPS	MRO	3, 4, 5, 6
4.	JODI JENSON	WAPA	MRO	1, 6
5.	KEN GOLDSMITH	ALT	MRO	4
6.	ALICE IRELAND	XCEL	MRO	1, 3, 5, 6
7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	5, 6, 1, 3
12.	MARIE KNOX	MISO	MRO	2
13.	LEE KITTELSON	OTP	MRO	1, 3, 4, 5
14.	SCOTT BOS	MPW	MRO	1, 3, 5, 6
15.	TONY EDDLEMAN	NPPD	MRO	1, 3, 5
16.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17.	DAN INMAN	MPC	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Jim Kelley	SERC EC Planning Standards Subcommittee	X				X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren	SERC	1
2.	Bob Jones	Southern Company Services	SERC	1
3.	Pat Huntley	SERC	SERC	NA
4.	Darrin Church	TVA	SERC	1

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Group	Jason Marshall	ACES Power Member Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ashley Gonyer	East Kentucky Power Cooperative	SERC	1, 3, 5
2.	Noman Williams	Sunflower Electric Power Corporation	SPP	1
3.	David Albers	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chuck	Matthews	WECC	1
2.	Allen	Chan	WECC	1, 3, 5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Individual	Tim Ponseti, VP	TVA Transmission Reliability Engineering & Controls	X		X		X	X			X	
10.	Individual	Antonio Grayson	Southern Company										
11.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
12.	Individual	Brandy A. Dunn	Western Area Power Administration	X					X				
13.	Individual	Aaron Staley	Orlando Utilities Commission	X									
14.	Individual	Chifong Thomas	BrightSource Energy, Inc.					X					
15.	Individual	Jose H Escamilla	CPS Energy	X		X		X					
16.	Individual	Mark Westendorf	MISO		X								
17.	Individual	Jennifer Wright	San Diego Gas & Electric	X		X		X					
18.	Individual	Patrick Brown	Essential Power, LLC					X					
19.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				
20.	Individual	John Burnett	Los Angrles Department of Water and Power	X		X		X					
21.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
22.	Individual	Michael Falvo	Independent Electricity System Operator		X								
23.	Individual	Kirit Shah	Ameren	X		X		X	X				
24.	Individual	Thad Ness	American Electric Power	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
25.	Individual	John Delucca	LCEC (Lee County Electric Cooperative	X		X							
26.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
27.	Individual	James Tucker	Deseret Generation & Transmission Cooperative	X		X		X					
28.	Individual	Brian Keel	Salt River Project	X		X		X	X				
29.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
30.	Individual	Anthony Jablonski	ReliabilityFirst										X
31.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
32.	Individual	Milorad Papic	Idaho Power Co.	X		X							
33.	Individual	Martyn Turner`	LCRA Transmission Services Corporation	X									
34.	Individual	Jonathan Fidrych	Tri-State Generation & Transmission Association, Inc.	X		X		X					
35.	Individual	John Martinsen	Public Utility District No. 1 of Snohomish County	X		X	X	X	X				
36.	Individual	Robert W. Creighton	Nova Scotia Power	X									
37.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
38.	Individual	Chris de Graffenried	Consolidate Edison Co. of NY, Inc.	X		X		X	X				
39.	Individual	Charlie Pottey	Sierra Pacific Power Co d/b/a NV Energy	X		X		X					
40.	Individual	Richard Vine	California Independent System Operator		X								
41.	Individual	charlie pottey	nevada power company dba nvenergy	X		X		X					
42.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
43.	Individual	Chris Scanlon	Exelon	X		X		X	X				
44.	Individual	Catherine Mathews	NorthWestern Energy (NWMT)	X		X		X					
45.	Individual	Robert Casey	Georgia Transmission Corporation	X									
46.	Individual	Kathleen Goodman	ISO New England Inc.		X								
47.	Individual	Bangalore Vijayraghavan	PG&E Company	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
48.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
49.	Individual	Steve Myers	Electric Reliability Council of Texas, Inc.		X								
50.	Individual	Ed O'Brien	Modesto Irrigation Districtt			X	X		X				
51.	Individual	R. Peter Mackin	Utility System Efficiencies, Inc.								X		

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: Thank you for following the new method of commenting that helps to avoid needless duplication of effort for the SDT. Your company name will be included in the participant list and the comments in full will be reviewed by the drafting team members under the Salt River Project comment/response.

Organization	Yes or No	Support Comments Submitted by Another Entity
Puget Sound Energy	Agree	Salt River Project
Sierra Pacific Power Co d/b/a NV Energy	Agree	WECC

1. **Do you agree with the description and components of the Stakeholder Process in the body of the footnote including the maximum capacity threshold (currently shown as 'x' MW but the SDT will fill in the value after the data request is complete and will submit the value for industry comment and approval in the next posting)? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. For the maximum capacity item, please supply any technical rationale for your comment along with limiting conditions and any current criteria in use at your entity.**

Summary Consideration: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a stakeholder process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach.

Several commenters suggested that there should be no limitation on the amount of Load that could be shed under footnote 'b'. The SDT does not agree with this suggestion, as such an important consideration cannot be left open-ended. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW.

Several commenters asked about the distinction between long-term and near-term with respect to the use of footnote 'b'. The SDT has clarified the language to show that footnote 'b' is available for long-term planning as well as near-term planning but that the stakeholder process only needs to be used for near-term.

The following changes were made due to industry comments:

First sentence of footnote text: An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events.

Next to last sentences in footnote text: In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1.

Organization	Yes or No	Question 1 Comment
Salt River Project BrightSource Energy, Inc. Los Angrles Department of Water and Power Deseret Generation & Transmission Cooperative California Independent System Operator nevada power company dba nvenergy PG&E Company Utility System Efficiencies, Inc.	No	We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest deleting this sentence.Assigning a fixed “not to exceed” number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others.A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, “[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events”. It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fix maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving “safe harbor” to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the “not to exceed” amount.

Organization	Yes or No	Question 1 Comment
ACES Power Member Standards Collaborators	No	We disagree with placing an upper limit on the amount of firm load shed. Conceptually, it seems like a good idea but we do not believe that such a threshold could ever consider all of the potential issues that could arise and would cause the need to plan to shed firm load. This is especially true considering that the SAR clarifies that the upper threshold will be based on the existing planned load shedding values. Future issues cannot be considered by such a data request. Consider a situation in which a new transmission line was included in Planning Assessment but cannot be built because right of ways cannot be obtained. Should an upper limit be placed on planned load shed in such a situation?
Bonneville Power Administration	No	BPA does not support quantitative limits on planned interruption, as planners generally do not plan the system to interrupt demand for a single contingency. As stated in the proposed footnote b, "[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events." Setting a quantitative limit would push transmission planners to plan the system to meet such a limit for a single contingency in all cases. Moreover, a quantitative limit would be difficult to implement due to the wide variety of system configurations and conditions. BPA believes an appropriate amount would be dependent on the topography and the size of the system being planned.
Manitoba Hydro	No	The maximum limit 'x' MW should vary with system load level and voltage. For example, an 'x' MW interruption would be a very small fraction of a 5000 MW system load level compared to a 1000 MW load level. Similarly, interruption of 'x' MW could be equal to surge impedance loading of a 230 kV line, where as it would be a fraction of a EHV transmission line loading.
NorthWestern Energy (NWMT)	No	Comments: A fixed maximum number of MW for Non-Consequential Load

Organization	Yes or No	Question 1 Comment
		Loss should not be used in an industry-wide standard. There is too much diversity. We suggest that a fixed maximum number not be stipulated.
Response: The SDT does not agree with this suggestion, as such an important consideration cannot be left open-ended. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW.		
SERC EC Planning Standards Subcommittee	No	We do not agree with this approach since there is no technical basis for allowing load shedding. It is all an administrative process which could result in inconsistencies from area to area. If a single contingency results in a local network becoming temporarily radial, then load shedding within the local network should be allowed. A limitation of up to some maximum amount of load shedding (to be determined) should be imposed. This would provide a technical basis for load shedding, which would help ensure consistency.
Southern Company	No	Southern does not agree with this Stakeholder Process approach since there is no technical basis for allowing load shedding. It is all an administrative process which could result in inconsistencies from area to area. A more technical based approach was the one taken by the SDT in an earlier draft - temporarily radial concept. If a single contingency (Category B) results in a local network becoming temporarily radial, then load shedding within the local network should be allowed since it would not have any impact to the reliability of the transmission grid. A limitation of up to some maximum amount ('x' MW) of load shedding (to be determined) should be imposed. This would provide a technical basis for load shedding, which would help ensure consistency from area to area. Furthermore, this would provide a method for defining the "fringes" of the power system.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed		

Organization	Yes or No	Question 1 Comment
Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process (“footnote b”), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC’s proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. The SDT agrees with you that there should be an upper limit on the amount of Firm Demand that can be shed. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote ‘b’ involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote ‘b’ utilization at 75 MW.		
TVA Transmission Reliability Engineering & Controls	No	TVA believes that the Stakeholder process is burdensome and should not be required for all levels of footnote b use. TVA beleives that the Stakeholder process should only be used for larger amounts of planned load drop. TVA would like to propose the following: For load loss of less than 50 MW - only TP approval is required; for load loss up to 100 MW - PC approval is required; for load loss up to 300 MW - RRO approval is required. Any load loss over 300 MW would require both RRO & NERC approval. The Stakeholder process would be required for any load loss of 100 MW or more. TVA is basing these levels using OE-417 as a starting point - which must be filed for an uncontrolled load loss of 300 MW as well as load shedding of 100 MW or more implemented under emergency operational policy. TVA believes that the 300 MW is the maximum amount of load that can be dropped without obtaining special permission from both NERC and the RRO.
Response: The SDT does not agree with this suggestion, as the Order 762 data request showed that there were no utilizations of		

Organization	Yes or No	Question 1 Comment
footnote 'b' involving more than 75 MW. Therefore, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW. The data request also showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW.		
MISO	No	Transmission planning that relies on planned or controlled interruption of non-consequential firm load following loss of a single transmission facility should not be acceptable and removal of footnote 12 should be considered or a modification to allow its use only in conjunction with a petition to FERC to waive (on an exception basis) the requirement to maintain firm load service for a specifically identified system configuration issue warranting Footnote 12's application. If it is determined that a footnote provision is required in the standard, we agree with the description and components of the Stakeholder Process in the body of the footnote, but reserve judgment on the value of the "x" that sets the maximum amount of MW load loss. Also, we have comments on the reference to Attachment I. Please see our comments under Q5.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a stakeholder process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW.		

Organization	Yes or No	Question 1 Comment
See response to Q5.		
San Diego Gas & Electric	No	We don’t support the changes.
Public Utility District No. 1 of Snohomish County	No	
Response: Without any reasons being supplied, the SDT is unable to respond to this comment.		
Essential Power, LLC	No	Although we agree with the majority of the content of the footnote, we’re not sure that using a specific amount of load as the bright-line threshold is appropriate. For example, if we make the limit 25 MW, this will have a different impact on different entities, in different regions. For a small TP that may only have a total of 200 MW of load, 25 MW is a significant amount of their overall obligation. For an area with 40,000 MW of load, 25 MW is hardly significant. Additionally, the nature of the load must be taken into consideration as well. Some types of load are more acceptable to lose than others; again, this may vary from region to region.Although we don’t have a specific recommendation or solution regarding these issues, I would urge the SDT to take these into consideration in their next revision. The sentence that starts with “When interruption of Firm Demand is utilized...” is confusing as it seems this sentence should only refer to the limited circumstances mentioned within footnote b
Response: The Order 762 data request showed that the average value of footnote ‘b’ utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. No change made. The SDT believes that in context the sentence you reference is clear; no change made.		
Tacoma Power	No	The layout of Table 1 with “No 12” does not actually indicate that load loss is allowed for those specific contingencies. Also the wording of the

Organization	Yes or No	Question 1 Comment
		footnote appears to require all Non-Consequential Load Loss to go through the attachment 1 process, not just P1.1 to P1.5, P2.1 and P3.1 to P3.5. Instead P1.1 to P1.5 and P3.1 to P3.5 should say “Yes per Attachment I” and Footnote 12 should be eliminated entirely. Since P2.1 is a new requirement with Version TPL-001-03, the recent NERC survey did not capture utilities currently using Non-Consequential Load Loss to address opening a line without a fault. Furthermore, some utilities may not identify problem lines until their first assessment using TPL-001-3. P2.1 should have a new footnote reading “For this contingency, load which is served radial from a remaining single source line may be shed as if it were Consequential load.” Technical Background: Parallel transmission lines serving remote load commonly will not perform with a P2-1 contingency, particularly when the strong source is opened. These issues are particularly common with load in rural settings and the cost to meet urban reliability expectations will be disproportionally expensive. Utilities will be encouraged to configure their system radially, which will be less reliable to meet this rare contingency. FERC has not specifically addressed load shedding associated with open ended lines. In order 693 the Commission was responding to the contingencies in TPL-001-1 that included footnote b. In order 762 and the NOPR RM12-1-000, FERC continues to reference applicability of footnote b to the TPL-001 defined single contingencies, but was otherwise prepared to accept Firm Load Loss for the single contingencies in TPL-001-2 P2.2 to P2.4. In the TPL-001-2, the category of “P2-Single Contingency” expanded to include both a new contingency of an open ended line, and various bus and breaker faults that previously were considered as Multiple Contingency.Based on our experience the likelihood of a line opening is significantly less than for line equipment faults. In addition, during human error caused line open events, personnel are on-site to affect quick restoration. This standard should not impose an upper limit because any planned large

Organization	Yes or No	Question 1 Comment
		load shedding will be reviewed and approved by the applicable regulatory authority. Pending the survey outcome, a limit of 3000 MW consistent with the CIP-002-5 Critical Asset level may be useful if the SDT believes an upper limit is needed.
Response: The SDT believes that the layout of Table 1 is clear in its intent that the circumstances covered by footnote 12 permit Load loss by exception and that the footnote pertains only to those Contingency types where the footnote appears. No change made. Although P2.1 is a “new” event, the resulting system will be the same as that following many P1.2 events; therefore, the SDT does not see a need to add a new footnote to P2.1. No change made. The SDT does not agree with this suggestion, as such an important consideration cannot be left open-ended. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote ‘b’ involving more than 75 MW. Based on this fact and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote ‘b’ utilization at 75 MW.		
Independent Electricity System Operator	No	Specific to the language used in footnote b, we agree with the concept of an approval process for determining the acceptable level of Firm Demand interruption applicable in a jurisdiction, and do not agree with prescribing a fixed MW threshold for a continent-wide acceptable Firm Demand interruption.Therefore, we recommend removing the last sentence in footnote b) which reads “In no case can the planned Firm Demand interruption under footnote ‘b’ exceed ‘x’ MW.” and also the same sentence from Attachement 1 section III. We believe there should not be a fixed limit on the amount of Firm Demand interruption, for reasons explained below in answers to Questions 4 and 5. As part of a reliability standard, the footnote should clarify the conditions under which load curtailment will be allowed, including mention of processes necessary to manage special circumstances. We generally agree with the reference to Attachment 1, but have concerns

Organization	Yes or No	Question 1 Comment
		about the components of the Stakeholder Process described in Attachment 1, for reasons described in answers to Questions 2, 3 and 4.
Response: The SDT does not agree with this suggestion, as such an important consideration cannot be left open-ended. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW. See responses to Questions 2, 3, 4, and 5.		
Ameren	No	We believe that the NERC Glossary contains an adequate definition for Firm Demand, which does not include Interruptible Demand or Demand-Side Management Load. We do not believe that Interruptible Demand or Demand-Side Management Load needs to be mentioned in the footnote b) as these types of Demand are not Firm Demand. Interruptible Demand can be cut at any time and may contain Demand-Side Management components, and may be direct controlled by the System Operator.
Response: The SDT believes that mention of Interruptible Demand and Demand-Side Management Load within footnote 'b' adds further clarity. No change made.		
American Transmission Company	No	ATC agrees with the 'x' MW statement in footnote 'b' , however, supports a maximum threshold value of 300 MW because this is the load loss threshold that the DOE deems to be significant enough to warrant a NERC system event investigation.
Response: The SDT does not agree with this suggestion. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW.		
Salt River Project	No	Additional comment from SRP for Q #5.

Organization	Yes or No	Question 1 Comment
Consolidate Edison Co. of NY, Inc.	No	See reply to Question 5
Response: Please see response to Q5.		
Lincoln Electric System	No	LES suggests the following changes to Footnote B/12 to further clarify the drafting team's intent. Under Footnote B/12, recommend the first sentence be modified to state "An objective of the planning process is to minimize the likelihood and magnitude of interruption...". Additionally, please clarify the reference to the Near-Term Transmission Planning Horizon while remaining silent on the Long-Term Transmission Planning Horizon. Does Appendix 1 apply to the Long-Term Transmission Planning Horizon as well as the Near-Term Transmission Planning Horizon?
Response: The SDT agrees with your suggested substitution of the word "is" for the words "should be" in the first sentence of the footnote. An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. The SDT has clarified the language to show that footnote 'b' is available for long-term planning, as well as near-term planning, but that the stakeholder process only needs to be used for near-term. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1.		
LCRA Transmission Services Corporation	No	Footnote 12 is applied in column labeled "Non-Consequential Load Loss Allowed." However, the last sentence of the proposed Footnote 12 switches from using the terms Consequential Load Loss and Non-Consequential Load Loss to using the term "Firm Demand." The term "Firm Demand" should be revised to "non-Consequential Load Load loss."

Organization	Yes or No	Question 1 Comment
		In addition, the application of Footnote 12 to the P3 contingency category should be removed.
Response: The SDT agrees with your change and will use the term "Non-Consequential Load loss." The SDT does not agree that footnote 12 should be removed from the P3 Contingency category. The SDT clarifies that the Planning Events for which footnote 12 is applicable were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011) in its consideration of TPL-001-2. The proposed changes are outside the scope of this project, which aims to clarify the stakeholder approval process. No change made.		
Tri-State Generation & Transmission Association, Inc.	No	There are several points that we disagree with in terms of the Stakeholder Process in the body of the footnote. First, the footnotes are not written in a manner so as to clearly be only applicable to Planning Standards. Many parts of the footnotes and the Attachment I can be misconstrued as Operational requirements. For example, the sentence that states "Curtailment of firm transfer..." should state "Planned curtailment of firm transfer..." Second, we disagree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest removal of this sentence.Assigning a fixed "not to exceed" number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others.A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, "[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events". It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fixed

Organization	Yes or No	Question 1 Comment
		maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Lastly, in an effort to develop a clearer and more transparent compliance standard, it is recommended that the additional requirements imposed by this footnote be broken into separate requirements set forth within the body of the standard itself. Do not imbed requirements in footnotes.
Response: Because this footnote can only be applied to this specific standard, there should be no confusion as to the applicability to planning. No change made. The SDT does not agree with this suggestion, as such an important consideration cannot be left open-ended. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote ‘b’ involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote ‘b’ utilization at 75 MW. The SDT disagrees with your characterization that requirements are being imbedded within the footnote. The requirement is clearly stated within the body of the standard. The footnote is simply clarifying those special circumstances where some relief from a strict interpretation of the requirement is permitted. No change made.		
Hydro-Quebec TransEnergie	No	Comments: It is difficult to establish the maximum value for acceptable Firm Demand interruption. For example, an entity may have an acceptable maximum load loss to avoid impacts on the grid such as generation trip-outs. For Hydro-QuÃ©bec TransÃ‰nergie (HQT), in the QuÃ©bec Interconnection, this value is above 1,000 MW. No maximum value should be posted in Footnotes 12 and ‘b’, since it is specifically related to system design and Interconnection size (inertia). Let us keep in mind that the goal of the TPL standards is not service continuity of local loads but global reliability of the system. Even though service continuity is important, TPL

Organization	Yes or No	Question 1 Comment
		standards should not address this issue by posting a maximum allowable load loss. Moreover, HQT considers that a Stakeholder Process such as seen in Attachment I has no place in a standard and its footnotes. Mainly, the Stakeholder Process doesn't consider that entities may have their own regulatory authorities with different processes, which do not specifically establish this load loss value.
Response: The SDT does not agree with this suggestion, as such an important consideration cannot be left open-ended. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW. Industry and the NERC BOT have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The SDT is now attempting to address FERC's concern expressed in their Remand Order 762 that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process, is vague, unenforceable, and not responsive to the previous Commission directives on this matter. The draft posted for comment adds detail and specificity to the already-approved approach. The SDT does not believe it appropriate to move away from the industry and BOT approved Stakeholder Process approach. No change made.		
Exelon	No	For TPL-001, the wording for footnote 12 does not make clear that DSM would be allowed without the Attachment 1 procedure. ComEd suggests the following wording change:12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to ensure that BES performance requirements are met. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements (other than Interruptible or Demand Side Management load), such interruption is limited to circumstances where the Non-Consequential

Organization	Yes or No	Question 1 Comment
		Load Loss is meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 12 exceed 'x' MW. For TPL-002, the wording of footnote "b" is not totally clear that it applies only to non-consequential load shed and not consequential load shed. ComEd suggests that the wording of footnote "b" be changed as shown:b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to ensure that BES performance requirements are met. When interruption of Firm Demand (other than in (1) or (2) above) is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 'x' MW.
Response: The SDT believes that footnote 12, as written and taken in context of the entire proposed TPL-001-2a standard, is clear. Similarly, the SDT believes that footnote 'b' is clear, as well. No change made.		
ISO New England Inc.	No	For single contingency events, footnote 12 should be eliminated. Planning the electric system for non-consequential load loss as a means to address a single contingency should not be acceptable. If the footnote is to remain, as a minimum the attachment should be

Organization	Yes or No	Question 1 Comment
		changed to increase the emphasis on the near term nature of the use of non-consequential load shedding.
Response: The SDT disagrees with your suggestion to remove footnote 12 because there are some limited situations when considering the entire North American grid where Non-Consequential Load loss may be necessary. No change made. The SDT has clarified the language to show that footnote 'b' is available for long-term planning, as well as near-term planning, but that the stakeholder process only needs to be used for near-term. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1.		
South Carolina Electric and Gas	No	SCE&G does not agree with the proposed modifications to footnote b. SCE&G believes the original footnote b is appropriate and consistent with the Energy Policy Act of 2005.SCE&G cites several statements in the Energy Policy Act of 2005 as justification for our position.1. The Energy Policy Act of 2005 states: "The term 'reliability standard' means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity."It also states, "This section does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services."SCE&G believes the proposed modifications to footnote b will result in building or enlarging facilities to meet the proposed requirements.

Organization	Yes or No	Question 1 Comment
		Also, any requirement that disallows load interruption or limits the amount of load interruption infringes on the stated limitation on the ERO to not set and enforce compliance with standards for adequacy.2. It also states: The term 'reliable operation' means operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."In this statement there is no mention of disallowing the interruption of firm load. It only requires that instability, uncontrolled separation, or cascading failures not occur. SCE&G believes the proposed changes to footnote b are beyond the authority granted to the ERO by the Energy Policy Act.3. It also states: ''Nothing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard, ..."SCE&G believes the proposed modifications to footnote b infringe on the state's authority to address adequacy and reliability of electric service within the State.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.		

Organization	Yes or No	Question 1 Comment
Electric Reliability Council of Texas, Inc.	No	As an initial matter, ERCOT does not believe the planning process should allow for non-consequential load shedding under single contingency conditions. However, if the SDT elects to retain a vehicle for such exceptions, it should establish objective, reliability based criteria that lend themselves to inclusion in a reliability standard. This is consistent with the general approach for reliability standards, which prescribe the "what", not the "how". If the exceptions are based on objective criteria that are known upfront, and those criteria reflect appropriate reliability based technical justifications, then the risk of unwarranted exceptions to the general prohibition due to misuse of the exception process is mitigated. Furthermore, the exception process should be external to the NERC Reliability Standards (e.g. in the Rules of Procedure), which should merely reference authorized exceptions granted pursuant to that process. In no case should a reliability standard mandate a stakeholder process in any respect, procedural or substantive. In ISO/RTO regions, stakeholder processes fall within ISO/RTO governance matters. These issues are beyond the purview of NERC Reliability Standards. In other regions, although the relevant functional entities do not have stakeholder processes analogous to ISOs/RTOs, any relevant processes are similarly beyond the scope of the reliability standards. Accordingly, the SDT should eliminate all revisions related to the establishment of a stakeholder process. As discussed in response to question 5, FERC is not requiring this approach, but rather has only provided guidance with respect to ways to possibly bring the prior proposal in line with applicable regulatory approval standards for reliability standards. Additionally, as a general matter, substantive reliability standards requirements should not be imbedded within a footnote to a requirement. In this case, not only is there a substantive requirement imbedded in the footnote, there is also a substantial attachment (which must become part of the enforceable standard requirements)...and, to make it worse, the

Organization	Yes or No	Question 1 Comment
		attachment is an attachment to the footnote, rather than an attachment to and referred to by a reliability standard requirement.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. The SDT disagrees with your characterization that requirements are being imbedded within the footnote. The requirement is clearly stated within the body of the standard. The footnote is simply clarifying those special circumstances where some relief from a strict interpretation of the requirement is permitted. No change made.		
Modesto Irrigation Districtt	No	We do not agree with the concept of non-consequential load loss in light of historic application of N-1 criteria, that only provides for consequntial load loss.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability		

Organization	Yes or No	Question 1 Comment
would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.		
Southwest Power Pool Reliability Standards Development Team	Yes	As a concept we agree with the stakeholder process. We would like clarification on why only the Near Term was used for non-consequential load loss and not both Near and Long term. It seems that depending on the time frame we would be held to different requirements of the standard.
Response: The SDT has clarified the language to show that footnote 'b' is available for long-term planning, as well as near-term planning, but that the Stakeholder Process only needs to be used for near-term. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1.		
MRO NSRF	Yes	The NSRF agrees with the 'x' MW statement in footnote b. The NSRF suggests a maximum threshold value of 300 MW because this is the load loss threshold that the DOE deems to be significant enough to warrant a NERC system event investigation.To support the inclusion of planning to use up to 300 MW of firm load shedding, registered Transmission Planning entities or regional planning entities should provide a TPL type analysis that demonstrates the use of planned firm load shedding allows BES equipment to stay within emergency thermal, voltage, and frequency ranges, and would not cause instability, uncontrolled separation, and cascading as defined in the FPA Section 215.
Idaho Power Co.	Yes	Maximum threshold for Planned Firm Demand interruption should be based on a previous year recorded peak demand. For instance for recorded peak demand of more than 3,000 MW the maximum treshold should be

Organization	Yes or No	Question 1 Comment
		greater than 300 MW.
Duke Energy	Yes	Situations where use of footnote 'b' would be appropriate can't be readily characterized with criteria leading to some "technically justified" maximum capacity threshold for interruption. That being the case, a maximum capacity threshold could be established based upon other criteria, such as the 300 megawatt threshold for DOE disturbance reporting.
Response: The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW.		
Georgia Transmission Corporation	Yes	Please remove the "is" as shown below:"12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to ensure that BES performance requirements are met. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss [IS] meets the conditions shown in Attachment 1. In no case can the planned FirmDemand interruption under footnote 12 exceed 'x' MW."
Response: The SDT agrees with your suggested substitution of the word "is" for the words "should be" in the first sentence of the footnote. An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events.		
LCEC (Lee County Electric Cooperative		"No comment as we have no Firm Demand / Load customers."
American Electric Power	Yes	AEP believes it can support the language at this stage, but would like to

Organization	Yes or No	Question 1 Comment
		revisit this after the MW threshold has been determined.
Arizona Public Service Company	Yes	
Orlando Utilities Commission	Yes	
CPS Energy	Yes	
City of Austin dba Austin Energy	Yes	
Nova Scotia Power	Yes	
Response: Thank you for your support.		

2. **Do you agree with the description and components of the the Stakeholder Process in Section I of Attachment I? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: Comments raised several concerns on the following issues:

Stakeholder process is not needed: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a stakeholder process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach.

Proposed process duplicates or conflicts with existing regulator/RTO processes: The SDT agreed with the comments and revised Footnote 12 accordingly. The text now allows for an existing process to be utilized, as long as it meets the criterion set out in Attachment 1, Section I.

Scope of Stakeholder Participants: Some comments reflected concern that the term "all affected stakeholders" in Attachment 1, Part I was too broad. The SDT has accepted the commenters' view and has deleted 'all'.

Clarification on need for annual Stakeholder Review: Commenters requested clarification as to whether the stakeholder processes has to be repeated for each annual assessment for a project if the process has confirmed for that specific project it is acceptable to curtail a firm demand. The SDT has added language to indicate that the Stakeholder Process does not have to be repeated for each annual assessment if the process has confirmed for a specific project that it is acceptable to curtail a Firm Demand, provided that the parameters have not changed. If any changes have occurred to the original parameters, these issues must then be addressed in the Stakeholder Process before that Planning Assessment can be completed.

Part I 2 b. Public Notification: The SDT agrees with the comment that: "Specific applications of the planned Firm Demand interruption under footnote 12" could be considered to require detailed descriptions of each and every contingency that could lead to use of footnote 'b' and is not necessary for the public notification. The language has been changed to clarify the SDT's intent.

Implementation Plan: Several commenters mentioned that this process could turn out to be lengthy and that the Implementation Plan should take this into account. The Implementation Plan for this project hasn't changed from the one that was submitted with the original filing, and is currently set at 60 months for footnote 'b'.

Dispute resolution process is not required: The SDT concluded that a dispute resolution process is an essential part of the process. The attachment language does not present any constraints on such a process; it just requires that an entity has a method to resolve disputes.

The following changes were made due to industry comments:

Main Body of footnote text: In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1.

Attachment 1 – Section I, last sentence: The responsible entity can utilize an existing process or develop a new process. The process must include the following:

Attachment 1 – Section I, Bullet 1: Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues

Attachment 1 – Section 1, Bullet 2: Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:

Attachment 1 – Section I, Bullet 2b: Specific location(s) of the planned Firm Demand interruption under footnote 'b'

Attachment 1 – Section I, last paragraph: An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

Organization	Yes or No	Question 2 Comment
Salt River Project	No	We suggest removing item 5, "A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction".

Organization	Yes or No	Question 2 Comment
BrightSource Energy, Inc. Los Angrles Department of Water and Power Deseret Generation & Transmission Cooperative nevada power company dba nvenergy PG&E Company Modesto Irrigation District Utility System Efficiencies, Inc.		Given that the “applicable regulatory authorities or governing bodies responsible for retail electric service issues” are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?
Response: The SDT believes that a dispute resolution process is an essential part of the Stakeholder Process. The SDT believes that the dispute resolution process should include a method for accounting for the cost/benefit if it is an issue for the region. The attachment language does not present any constraints on such a process; it just requires that an entity has a method to resolve disputes. No change made.		
MRO NSRF American Transmission Company	No	Order 890 already requires Transmission Planners to solicit the input of affected stakeholders on TPL standards. Order 890 does not provide prescriptive details regarding the stakeholder process for the TPL standards, which includes footnote ‘b’. In additions, there is no clear justification to indicate that the process with regard to footnote ‘b’ warrants more prescription stakeholder process details than the rest of the TPL standards. So, the NSRF suggests that Section II be removed. If Section I is not removed, then NSRF suggests at least replacing “all affected stakeholders” with “all known affected stakeholders” or “appropriate known affected stakeholders” because an entity can develop a list of all known affected entities for compliance purposes and document that the meeting was open to them and that they were notified. An entity cannot demonstrate that a stakeholder meeting is open

Organization	Yes or No	Question 2 Comment
		to unknown stakeholders or that it notified unknown stakeholders.The use of "all" in mandatory zero defect standards is not appropriate in NERC standards, especially when potential large diverse populations such as affected stakeholders must be considered.

Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.

The SDT has tried to provide some technical/quantitative criteria in Section II to assist affected stakeholders in understanding why Firm Demand is planned to be interrupted. No change made.

The SDT has accepted your comment and has replaced "all affected stakeholders" with "affected stakeholders."

> Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
>
> Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:

Organization	Yes or No	Question 2 Comment
TVA Transmission Reliability Engineering & Controls	No	Please see comment for question #1. TVA believes that TPs should be able to drop some load without having to go thru a burdensome process. Only the larger load drop levels should require a Stakeholder review.
SERC EC Planning Standards	No	We recommend using a technical basis for load shedding instead of a Stakeholder

Organization	Yes or No	Question 2 Comment
Subcommittee		Process.
Southern Company	No	Southern recommends using a technical basis for load shedding (see comment in Question 1 above) instead of a Stakeholder Process.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. Please also see response to Q1.		
ACES Power Member Standards Collaborators	No	(1) Attachment 1 should clarify that it only applies when approval is not required by the regulatory body with authority over retail service, such as local regulatory authorities and state public utility commissions. This includes whether the approval is required by NERC rules or another regulatory body's rules. It does not make sense for the Transmission Planner or Planning Coordinator to duplicate a process that is already required by another regulatory body that satisfies due process. As an example, why should the Transmission Planner and Planning Coordinator have a dispute resolution process if the regulatory body already has a dispute resolution process that can be used. It also does not make sense for the Transmission Planner and Planning Coordinator to be compelled to have a stakeholder comment process when the local regulatory body's approval is required. Having such a process is duplicative and unnecessary.

Organization	Yes or No	Question 2 Comment
		(2) Many RTOs have well organized stakeholder processes that could be utilized to satisfy Attachment I. Because the TPL standards apply to both the PC and TP, one may believe the both the PC and TP need to have these stakeholder processes. Rather, we think that the TP should be able to rely on its PC's stakeholder process. We suggest Attachment I should clarify that this is acceptable and that both entities are not required to have redundant processes. The most important point is that stakeholders have an opportunity to participate.
Response: The SDT has revised the Stakeholder Process to allow use of an existing regulator/RTO stakeholder process, as long as it meets the criterion in Attachment 1, Section I. The responsible entity can utilize an existing process or develop a new process. The process must include the following: The SDT believes that a dispute resolution process is an essential part of the stakeholder process. No change made.		
Bonneville Power Administration	No	Regarding the stakeholder process and dispute resolution, BPA believes that a decision for Firm Demand interruption needs to be made based on what is best for the system, not a specific dispute resolution process.
Western Area Power Administration	No	The addition of the "Stakeholder Process" outlines in Attachment 1 is so onerous so as to persuade entities NOT to attempt the use of Footnote b) OR 12). Is this the intent?
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does		

Organization	Yes or No	Question 2 Comment
not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.		
MISO	No	(1) The process presented in Section I of Attachment I is overly prescriptive. This Section needs only to stipulate that the proposed utilization of the footnote be reviewed through an open and transparent stakeholder process developed or approved by the Regional Entities (since the RE will eventually need to review and assess the reliability impact of such utilization), with supporting information. (2) There is no basis to support allowing the utilization of the footnote in the Near-Term Transmission Planning Horizon of the Planning Assessment only. The footnote itself leaves the time frame wide open, and does not explicitly or implicitly restrict its utilization to only the Near-Term horizon. Often, in the long-term planning horizon, when approval for transmission addition or reinforcement cannot be obtained for whatever reasons, utilization of the footnote is considered and adopted, subject to stakeholder's and regulatory authority's approvals. Note that it is impractical to add or reinforce transmission facilities in a near-term planning (e.g. Year One) time frame and hence the proposed provision does not allow for utilizing the footnote for the interim period before new or reinforced transmission facilities are put in place. We suggest to remove the word "Near-Term". (3) Requirement 8 of the Transmission Planning Standard TPL-001-3 requires notification and response requirements for a Planning Coordinator and/or Transmission Planner for the Planning Assessment to any registered entity having a reliability interest. Attachment I does not recognize this requirement. Attachment I must be coordinated with this administrative requirement.
Response: (1) Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission		

Organization	Yes or No	Question 2 Comment
remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. (2) The Stakeholder process is required prior to planned interruption of Firm Demand in the near term, but does not preclude application in the long term. The SDT clarified the language concerning near- and long-term applications of footnote 'b'. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. (3) Requirement R8 imposes an obligation on the Planning Coordinator and Transmission Planner to distribute its Planning Assessment to: "any functional entity that has a reliability related need and submits a written request for information …" Requirement R8 does not ensure the functional entity is aware that it may be affected by a plan to curtail firm Load so as to request information. If a Planning Coordinator or Transmission Planner has established a stakeholder process, as per Attachment 1, reporting of such a process under Requirement R8 is not prohibited. No change.		
Public Utility District No. 1 of Snohomish County	No	
San Diego Gas & Electric	No	We don't support the addition of stakeholder process language.
Response: With no reasoning provided, the SDT is unable to respond to this comment.		
Tacoma Power	No	Completing the entire stakeholder process on an annual basis, before the TPL study can be finalized, is not feasible due to long and unpredictable timelines for public involvement and regulatory approval. The stakeholder process should only be repeated when the technical basis as outlined in section II have changed, or when

Organization	Yes or No	Question 2 Comment
		there are new stakeholders. There are cases on the fringes of the system where Firm Demand Interruption as the preferred alternative in both the long term and short term, not as a temporary patch in Corrective Action Plan.To address these issues, Section I should read as:Before the use of Firm Demand interruption is allowed as an element in the Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of this mitigation is reviewed through an open and transparent stakeholder process. The responsible entity shall document the stakeholder process which shall include the following:1. Meetings must be open to all affected stakeholders including applicable regulatory Authorities or governing bodies responsible for retail electric service issues. 2. Notice must be provided in advance of meetings to all affected stakeholders, including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with: a. Date, time, and location for the meeting b. Specific applications of the planned Firm Demand interruption under footnote 12 c. Provisions for a stakeholder comment period 3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote 12 (as shown in Section II below) must be made available to meeting participants. 4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns. 5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction. During each Planning Assessment, the Transmission Planner or Planning Coordinator shall update the information outlined in Section II. If the annual hours of exposure to or the amount of Firm Demand has increase above the previously disclosed level(s), a new Stakeholder process shall be completed within one Calendar year.Every three years the stakeholder process shall reoccur to allow new stakeholders input to the process.
Response: The SDT has not adopted your proposed language: "Before the use of Firm Demand interruption is allowed as an element in the Transmission Planning Horizon of the Planning Assessment," as the SDT believes the reference to the Corrective Action Plan is		

Organization	Yes or No	Question 2 Comment
superior. However, the SDT has added language to indicate that the Stakeholder Process does not have to be repeated for each annual assessment if the process has confirmed for a specific project that it is acceptable to curtail a Firm Demand, provided that the parameters have not changed. If any changes have occurred to the original parameters, these issues must then be addressed in the Stakeholder Process before that Planning Assessment can be completed. An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application. The SDT agrees that application of a stakeholder process could be lengthy and, consequently, has already provided a 60-month implementation plan. No change made. The information in Section II is required as part of the Stakeholder meeting. No change made.		
Manitoba Hydro	No	A stakeholder process should not be required in jurisdictions where a legislation already authorizes interruptions, as consent of stakeholders cannot override legislation. If Firm Demand interruptions require the approval of regulatory authority as described in Section III (for interruptions over 25 MW or if voltage level of the contingency is greater than 300 kV), the stakeholder process described in Section I would become a redundant process. Does Section I exclude Firm Demand interruptions addressed under Section III?
Response: The SDT has revised the stakeholder process to allow use of an existing regulator/RTO stakeholder process, as long as it meets the criterion in Attachment 1, Section I. The responsible entity can utilize an existing process or develop a new process. The process must include the following For interruptions over 25 MW, or if voltage level of the Contingency is greater than 300 kV, then both the Stakeholder Process and the Section III regulatory review are still required.		
Independent Electricity System Operator	No	(1) The process presented in Section I and the rest of Attachment I is overly prescriptive and lengthy. As part of a reliability standard, the footnote and process must focus on the impact that Firm Demand interruption (or Load Rejection) would

Organization	Yes or No	Question 2 Comment
		have on the reliability of the Bulk Electric System and this aspect is covered in Section III. This Section needs only to stipulate that the proposed utilization of the footnote be reviewed through (a) an open and transparent stakeholder process and (b) approved by a relevant reliability authority such as the ERO, Regional Entity or applicable governmental authority since this authority will eventually need to review, assess and approve the reliability impact on the interconnected BES of such utilization, with supporting information. Reliability issues and their assessment and approvals should be dealt with by the applicable reliability authority. Details of other aspects of Firm Demand interruption, mainly the Stakeholder review and approval process and issues pertaining to the quality of service, economic and welfare impacts of Firm Demand interruption, assessment of alternatives (including their economic and welfare impacts), etc. should be dealt with by the regulatory authority or government body of each jurisdiction (in particular, in non-US jurisdictions), as is the normal practice for all other Transmission Planning activities. (2) There is no basis to support allowing the utilization of the footnote in the Near-Term Transmission Planning Horizon of the Planning Assessment only. The footnote itself leaves the time frame wide open, and does not explicitly or implicitly restrict its utilization to only the Near-Term horizon. Often, in the long-term planning horizon, when approval for transmission addition or reinforcement cannot be obtained for whatever reasons, utilization of the footnote is considered and adopted, subject to stakeholders' and regulatory authorities' approvals. Note that it is impractical to add or reinforce transmission facilities in a near-term planning (e.g. Year One) time frame and hence the proposed provision does not allow for utilizing the footnote for the interim period before new or reinforced transmission facilities are put in place. We suggest removing the word "Near-Term".
Response: (1) The SDT believes that the stakeholder process must involve all stakeholders affected and provide specific information of the intended purpose and scope so they can understand the reason for Firm Demand interruption is appropriate. Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability		

Organization	Yes or No	Question 2 Comment
Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. The SDT agrees that application of a stakeholder process could be lengthy and, consequently, has provided a 60-month implementation plan. (2) The Stakeholder process is required prior to planned interruption of Firm Demand, but does not preclude application in the long term. The SDT has clarified the language concerning near- and long-term use of footnote 'b'. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1.		
Ameren	No	We request that Item 1 be modified to include representatives of stakeholders because it may not be practical to open a meeting to all affected stakeholders. The new sentence of Attachment 1 should read, "Meetings must be open to all affected stakeholders, or their representatives, including applicable regulatory authorities or governing bodies responsible for retail electric service issues." Also, requirements for a meeting location would sem to eliminate electronic partipation via webex. It would seem more practical for a TP or PC to host a specific webex to present and discuss the issues associated with the need to drop Firm Demand. Further, we request that a MW threshold be included before the Section I stakeholder process would begin, and believe that a minimum threshold of 10 MW of Firm Demand to be cut would be a reasonable value to initiate a stakeholder process.

Organization	Yes or No	Question 2 Comment
		Levels below 10 MW would be considered as “noise” in the planning horizon. We believe that an approval should be obtained in the Section I process, which would eliminate the need for Section III. By requiring an approval of the appropriate local governing bodies responsible for retail service issues (including rates), there is no need to agree on a cap to limit the amount of Firm Demand dropped.
Response: The SDT agrees that the term “all affected stakeholders” in Attachment 1, Part I is too broad. The SDT has accepted the commenters’ view and has replaced “all affected stakeholders” with “affected stakeholders.” The SDT has not included stakeholder representatives, as this too would make identification of same impossible. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with: The Stakeholder Process in Attachment 1 assumes that a meeting would be held; however, the language does not prohibit the use of other methods acceptable to the stakeholders. Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote ‘b’ and with footnote 12 in TPL-001-2. The Commission’s Order No. 762 found that NERC’s proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process (“footnote b”), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC’s proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.		
Consolidate Edison Co. of NY, Inc.	No	See reply to Question 5

Organization	Yes or No	Question 2 Comment
Salt River Project	No	Additional comment from SRP for Q #5.
Response: Please see response to Q5.		
LCRA Transmission Services Corporation	No	In the Proposed Revision to the Standard, Footnote 12 is applicable to the use of Non-Consequential Load Loss to relieve criteria violations resulting from P1, P2, and P3 category contingencies, however, Footnote 12 and Attachment I switch terms and begins using “Firm Demand.” Though it may be reasonable to characterize Non-Consequential Load Loss as a subset of Firm Demand not all Firm Demand is Non-Consequential Load Loss. The term “Firm Demand” as used in Footnote 12 and Attachment I should be replaced with “Non-Consequential Load Loss.” Application of the term “Firm Demand” in Footnote 12 and Attachement 1 introduces an ecomonic criteria to the TPL-001 Reliability Standard. For intstance, the interruption of “Firm Demand” as defined in the NERC Glossary may not require Non-Consequential Load Loss, however, this is an economic decision between the parties involved in the Firm Demand contract. In addition, a Transmission Planner or Tranmission Owner may or may not be a party to the Firm Demand contract. The process outlined in Attachment 1 applies to the P3 contingency category (through the application of Foontote 12) and thus represents a significant and substantive change in the reliability standard over previous standards. The reference to Footnote 12 should be deleted from the P3 contingency category.
Response: The SDT acknowledges that the references to Firm Demand interruption should reference Non-Consequential Load Loss. The SDT has made revisions to the TPL-001-2a Footnote 12 and Attachment I to show these changes. The SDT clarifies that the planning events for which footnote 12 is applicable were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011) in its consideration of TPL-001-2. The proposed changes are outside the scope of this project, which aims to clarify the stakeholder approval process. No change made.		
Tri-State Generation &	No	We disagree with Section I of Attachment I to the extent that there currently are several other venues through which stakeholder input is mandated. In addition, we

Organization	Yes or No	Question 2 Comment
Transmission Association, Inc.		do not believe NERC Reliability Standards have the authority to dictate stakeholder outreach processes. For several reasons, including the time required for public input, permitting, acquisition, and construction, most transmission projects take several years to build. TPs will develop plans to mitigate BES performance violations, but those plans may not be able to be constructed in time. The Footnotes do not allow planners to design temporary mitigation to accommodate real world construction issues, which are often complex in nature due to competing interests.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. The SDT agrees that application of a stakeholder process could be lengthy and, consequently, has provided a 60-month implementation plan.		
Duke Energy	No	Since item 2 describes the public notice that must be provided, the phrasing of 2.b should be revised to replace the words "Specific applications" with the words "Summary description". "Specific applications" could be considered to require detailed descriptions of each and every contingency that could lead to use of footnote 'b'. That level of detail could certainly be provided to meeting participants, but shouldn't be necessary for the public notice.
Response: The SDT agrees with the comment that: "Specific applications of the planned Firm Demand interruption under footnote		

Organization	Yes or No	Question 2 Comment
12" could be considered to require detailed descriptions of each and every contingency that could lead to use of footnote 'b' and is not necessary for the public notification. The language has been changed to clarify the SDT's intent. Specific location(s) of the planned Firm Demand interruption under footnote 'b'.		
California Independent System Operator	No	The process presented in Section I of Attachment I is overly prescriptive. Identifying the need for stakeholder consultation on this issue within the consultation process already employed by the Transmission Planner or Planning Coordinator should be sufficient detail. In particular, however, we suggest removing item 5, "A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction". Given that the "applicable regulatory authorities or governing bodies responsible for retail electric service issues" are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution? There is no basis to support only allowing the utilization of the footnote in the Near-Term Transmission Planning Horizon of the Planning Assessment. The footnote itself leaves the time frame wide open, and does not explicitly or implicitly restrict its utilization to only the Near-Term horizon. Often, in the long-term planning horizon, when approval for transmission addition or reinforcement cannot be obtained for whatever reasons, utilization of the footnote is considered. Note that it is impractical to add or reinforce transmission facilities in a near-term planning (e.g. Year 0ne) time frame and hence the proposed provision does not allow for utilizing the footnote for the interim period before new or reinforced transmission facilities are put in place. We suggest removing the word "Near-Term".
Response: The SDT has recognized that the requirement to notify all stakeholders is too broad and has replaced "all affected stakeholders" with "affected stakeholders." Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for		

Organization	Yes or No	Question 2 Comment
retail electric service issues Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with: The SDT believes the stakeholder process is required and it must provide specific information of the intended purpose and scope so stakeholders can understand the reason for Firm Demand interruption is appropriate. The SDT has debated the language and believe that it is appropriate. No change made. The Stakeholder Process is required prior to planned interruption of Firm Demand, but does not preclude application in the long term. The SDT has clarified the language concerning near- and long-term use of footnote 'b'. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1.		
Hydro-Quebec TransEnergie	No	The Stakeholder Process doesn't consider that entities may have their own regulatory authorities with different processes, which do not specifically establish load loss values. Also, the use of Firm Demand interruption in the Corrective Plan should not be limited only to the Near-Term Transmission Planning Horizon. It should also be allowed for the Long-Term horizon, at least for Multiple Contingencies.
Response: The SDT has revised the Stakeholder Process to allow use of an existing regulator/RTO Stakeholder Process, as long as it meets the criterion set in Attachment 1, Section I. The responsible entity can utilize an existing process or develop a new process. The process must include the following The Stakeholder process is required prior to planned interruption of Firm Demand, but does not preclude application in the long term. The SDT has clarified the language concerning near- and long-term use of footnote 'b'. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm		

Organization	Yes or No	Question 2 Comment
Demand interruption meets the conditions shown in Attachment 1.		
NorthWestern Energy (NWMT)	No	Comments: It is unclear how the dispute resolution process would treat stakeholders with different concerns. We suggest that Item 5 of Attachment 1 be deleted.
Response: The SDT believes that a dispute resolution process is an essential part of the Stakeholder Process. No change made.		
Georgia Transmission Corporation	No	Item #1 in Section I should be reworded: From This....”Meetings must be open to all affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues.” Reworded to say: “Meetings must be open to all affected NERC Registered Entities including applicable regulatory authorities or governing bodies responsible for retail electric service issues.”The concern is that stakeholders could be too broadly construed including residential, commercial, industrial customers, and even more so (i.e transitory customers). We recommend that the sentence be reworded as shown above. Additionally, GTC request feedback from the SDT's intent. Is a stakeholder meeting required every year a planning assessment is done showing that non-consequential load loss is required?
Response: The SDT believes that the current language is clear and that the suggested change does not add further clarity. No change made. The SDT has added language to indicate that the Stakeholder Process does not have to be repeated for each annual assessment if the process has confirmed for a specific project that it is acceptable to curtail a Firm Demand, provided that the parameters have not changed. If any changes have occurred to the original parameters, these issues must then be addressed in the Stakeholder Process before that Planning Assessment can be completed. An entity does not have to repeat the stakeholder process for a specific application of footnote ‘b’ utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.		

Organization	Yes or No	Question 2 Comment
ISO New England Inc.	No	With regard to Section I, in paragraph I.5, the stakeholder process includes a dispute resolution process. Existing ISO/RTO stakeholder processes are FERC approved and rigorous, requiring a dispute resolution process goes beyond the existing requirements in ISO/RTO tariffs. Item I.5 should be eliminated.
Response: The SDT has revised the stakeholder process to allow use of an existing regulator/RTO stakeholder process, as long as it meets the criterion set in Section I. The responsible entity can utilize an existing process or develop a new process. The process must include the following The SDT concluded that a dispute resolution process is an essential part of the process and no change was made to the process.		
South Carolina Electric and Gas	No	See response to question #1
Electric Reliability Council of Texas, Inc.	No	Please see ERCOT's response to Question 1.
Southwest Power Pool Reliability Standards Development Team	Yes	See comment From question 1
Response: Please see response to Q1.		
Lincoln Electric System	Yes	Although LES agrees in general with the description and components included as part of Section I, we suggest the following wording changes to enhance Section I. Recommend the drafting team delete item 2(c) as it is duplicative of item 4 which is more succinctly worded. Also, recommend additional wording be added to the end of item 3 to provide meeting participants with advanced notice of the information. As an example, "information...must be made available to meeting participants [ten days prior to the meeting]."

Organization	Yes or No	Question 2 Comment
Response: The SDT believes that the current language is clear and that the suggested change does not add further clarity. No change made.		
LCEC (Lee County Electric Cooperative		No comment as although we are a Firm Demand customer of another entity, we have no Firm Demand / Load customers and therefore would not perform the Stakeholder Process
Arizona Public Service Company	Yes	
Orlando Utilities Commission	Yes	
CPS Energy	Yes	
Essential Power, LLC	Yes	
American Electric Power	Yes	
City of Austin dba Austin Energy	Yes	
Idaho Power Co.	Yes	
Nova Scotia Power	Yes	
Response: Thank you for your support.		

3. Do you agree with the Information for Inclusion in the Stakeholder Process contained in Section II of Attachment I? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Summary Consideration: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach.

Based on industry comment, item 8 of Section II has been modified to clarify that adjacent Transmission Planners and Planning Coordinators are the relevant parties for assessment of potential overlapping use of Firm Demand interruption.

Based on industry comment, item 2.b of Section II has been modified to clarify the SDT's intent. However, the SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Such an assessment is already required under EOP-001-2.1b by the Transmission Operator and Balancing Authority. A similar requirement for the Transmission Planner/Planning Coordinator would rely on the same type of information and sources already required under the EOP standard.

Several commenters had concern about being required to provide the information in Section II, items 1, 2, 3 and 4. The SDT believes that this information is necessary for understanding the reliability impact and for stakeholders to make an informed decision.

The following changes were made due to industry comments:

Attachment 1, Section II, Bullet 2b: Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community

Attachment 1, Section II, Bullet 8: Assessment of potential overlapping uses of footnote 'b' including overlaps with adjacent Transmission Planners and Planning Coordinators

Attachment 1, Section III, last paragraph: Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.

Organization	Yes or No	Question 3 Comment
Southwest Power Pool Reliability Standards Development Team	No	We need clarification on the term planner in item 8 of section 2. Since the term isn't capitalized we would like to know if this was intended to mean Transmission Planner or a adjacent Planning Coordinator for identifying a seams issue. We would like see item 2b of section 2 removed this item isn't relevant to the standard and goes beyond the purpose of this standard. We understand that this is included for curtailment of load during emergency conditions (EOP001 Attach 1) but feel it is unnecessary in planning.
Response: The SDT agrees and item 8 of Section II has been modified accordingly. 8. Assessment of potential overlapping uses of footnote 'b' including overlaps with adjacent Transmission Planners and Planning Coordinators The SDT believes assessment of the impact of Firm Demand interruption to the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community		
Salt River Project BrightSource Energy, Inc.	No	We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the

Organization	Yes or No	Question 3 Comment
Los Angrles Department of Water and Power Deseret Generation & Transmission Cooperative Tri-State Generation & Transmission Association, Inc. California Independent System Operator nevada power company dba nvenergy PG&E Company Modesto Irrigation Districtt Utility System Efficiencies, Inc.		community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the “applicable regulatory authorities or governing bodies responsible for retail electric service issues”.
Response: The SDT believes that the provision of customers affected and the duration and assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is not solely administrative and is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been changed to clarify the SDT’s intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community		
MRO NSRF American Transmission Company	No	Order 890 already requires Transmission Planners to solicit the input of affected stakeholders on TPL standards. Order 890 does not provide prescriptive details regarding the information that should be included in the stakeholder process for the TPL standards, which includes footnote ‘b’. Stakeholders that participate in stakeholder meeting can ask for any information that they want regarding the

Organization	Yes or No	Question 3 Comment
		proposed use of Firm Demand interruption. They do not need a third party to prescribe what information they need or want. So, the NSRF suggests that Section II be removed. If Section II is not removed, then the NSRF suggests that at least Items 2b, 6, and 8 be removed from the listing. o Item 2b - The scope and content expectation for an assessment of the potential impact of the proposed Firm Demand interruption on the health, safety, and welfare of the community is basically broad, nebulous, and vague. The stakeholders would raise any specific, relevant questions or concerns in these areas if they exist without a prescriptive stipulation for this information in the TPL-002 standard. o Item 6 - The verification of that the TPL performance requirements will be met by the use of Firm Demand interruption is superfluous. Proposal to use Firm Demand interruption to meet the TPL-002 performance requirements would always be the result of identifying (i.e. verifying) what Firm Demand interruption is needed to meet the TPL-002 performance requirements. o Item 8 - Potential overlapping uses of footnot 'b' with adjacent planners will not always exist and would probably be rare. In addition, whenever the situation would exist, then any applicable adjacent planners would be affected stakeholders and would have the opportunity to attend the stakeholder meeting and raise any questions or concerns in that meeting without the stipulation of this information in the TPL-002 standard.

Response: Order 890 is not applicable to all NERC regions and is not a standard. No change made.

The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent.

2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community

Organization	Yes or No	Question 3 Comment
The SDT believes the wording regarding the TPL standards is necessary to ensure the focus on meeting the TPL standard's reliability requirements is not lost and that the end state following interruption of Firm Demand meets those requirements. No change made. The SDT believes application of a wide area view to the use of Firm Demand interruption is necessary to avoid reliability issues that would not be seen by an individual Transmission Planner or Planning Coordinator. There is no standard requirement for adjacent Transmission Planner/Planning Coordinator's to participate in Order 890 type processes therefore it must be addressed. No change made.		
SERC EC Planning Standards Subcommittee	No	We recommend using a technical basis for load shedding instead of a Stakeholder Process.
Southern Company	No	Southern recommends using a technical basis for load shedding instead of a Stakeholder Process.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.		
ACES Power Member Standards Collaborators	No	(1) We disagree with with including the Facilities that will exceed their rating and the applicable contingenices. We think this information should be treated as confidential. It could be used by bad actors to create outages within communities. The risk to the Bulk Electric System is higher than the benefit of sharing this information. (2) We disagree that the Transmission Planner should be required to provide an assessment on the health, safety and welfare of the community. First, the

Organization	Yes or No	Question 3 Comment
		stakeholders will have an opportunity to provide this information through either the Transmission Planner's stakeholder comment process or through the local regulatory agency's stakeholder comment process. Second, these planned interruptions in firm demand are expected to be short in nature so the impacts should be minimal. Third, an assessment on the health, safety and welfare of the community is an unnecessary burden on the utility and is better suited for local governments. Even if the utility should perform such an assessment, health, safety and welfare are ambiguous terms without clear parameters or expectations for the data. Does this mean that the Transmission Planner verifies police stations, fire departments, hospitals and other critical public support agencies are not included in the planned load shed? Most electric providers already do this when developing load shed plans and are likely not going to includes such customers in any load shed plan. Fourth, communities already have plans in place for the interruption of electricity so as long a critical customers are not shed, then the impacts are likely economic in nature. (3) Bullet 3 needs to be clarified that it is not an estimated frequency but rather a historical frequency. How do you estimate a frequency for a new planned load shed? It also needs to be clarified if the historical frequency is all instances within the Transmision Planner's area or just the specific location of the planned load shed. If it is all instances, it further needs to be clarified that it is only within its own TP area. (4) We do not believe that expected duration of the planned load shed should be required. Any duration will likely be a guess. When actual contingencies occur, the time of restoration varies. Consider the recent event in Arizona and Southern California. The report indicated that the TOP thought they could return the 500 kV line that initiated the event in a few minutes. They were unaware that the phase angle was too large to close. The expected duration is too speculative and should not be required. (5) We disagree with the need to include future plans to mitigate the planned load shed in all cases. For remote areas of the system, there simply may not be sufficient load growth to justify any other mitigation.

Organization	Yes or No	Question 3 Comment
		(6) Item 8 should be clarified that it applies only to the Planning Coordinator. The Planning Coordinator should coordinate all of its Transmission Planner's Planning Assessments. This would include evaluating planned load shedding.
Response: 1) The use of Firm Demand interruption and events involved should only affect local area issues and should not create issues for the BES that could be exploited by "bad actors." No change made. 2) The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. As stated, it is something that TP/PC's normally do. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community 3) Any estimate of future performance has to be based on some sort of available historical information, even for a new line/delivery. The SDT believes it is clear that for stakeholders to make an educated decision regarding Firm Demand interruption, the information must be provided for each instance of Firm Demand interruption use within the Transmission Planner/Planning Coordinator's area. No change made. 4) The SDT believes stakeholders need an expectation of the duration in order to evaluate the impact. No change made. 5) Possible future plans could include a decision not to mitigate the need for Firm Demand interruption. No change made. 6) The standard does not dictate who performs the assessment, only that one be performed. No change made.		
Bonneville Power Administration	No	BPA does not support including information under Sections II.2.a and II.2.b, estimated number and type of customers affected, or an assessment of the use of Firm Demand interruption on the health, safety, and welfare of the community as this information does not support reliability of the BES. If footnote b were applied, reliability of the BES is actually assessed by meeting the applicable TPL Standard for a single contingency with loss of load regardless of the type of customers or use of Firm Demand.
Response: The information is necessary to make an informed judgment and assessment, with stakeholder input, as to whether		

Organization	Yes or No	Question 3 Comment
reliability of the BES will be maintained. Evaluation of the consequences of an event is a part of assessing reliability. No change made. The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community		
TVA Transmission Reliability Engineering & Controls	No	Under Item #2 - TVA is not sure how to properly address "health, safety, and welfare of the community" from an regulatory standpoint. Please clarify what this would require - such as number of hospitals without emergency backup, etc? Also please see answer to question #1 - TVA beleives that only larger load drops should require a Stakeholder review.
Response: The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community See response to Q1.		
MISO	No	Again, this Section is overly prescriptive. This Section needs only to stipulate at a high level, the kind of information needed to support the proposed utilization of the footnote, leaving much of the detail to the application process overseen by the Regional Entities (given the RE will eventually need to review and assess the reliability impact of such utilization). We suggest the SDT to reduce this Section, or remove this altogether with appropriate insertion into Section I that address a general need for supporting information to be specified by the RE's review process.

Organization	Yes or No	Question 3 Comment
Independent Electricity System Operator	No	Again, this Section is overly prescriptive. This Section needs only to stipulate at a high level, the kind of information needed to support the proposed utilization of the footnote, leaving much of the detail to the application process overseen by the applicable reliability authority to review and assess the reliability impact of such utilization. We suggest the SDT to reduce this Section, or remove this altogether with appropriate insertion into Section I that address a general need for supporting information to be specified by the RA's review process. Also note that use of a "stakeholder process", as per FERC's concerns, must be crisp and clear.
Response: The SDT believes the information required provides what is necessary for a high-level assessment of the impact of utilizing Firm Demand interruption and is necessary for stakeholders to make an informed decision. No change made.		
Public Utility District No. 1 of Snohomish County	No	
San Diego Gas & Electric	No	We don't support the addition of stakeholder process language.
Response: Without specific comments, the SDT is unable to respond.		
Tacoma Power	No	Item II.2.b Since this is a stakeholder process, each stakeholder can make an assessment for themselves about the effect of Firm Demand interruption on the health, safety and welfare of the community. This requirement is too vague to be enforceable. Item II.5 Particularly in the case of P2.1 contingencies, utilities may not have any plans to eliminate load shedding "at the fringes of various systems" as the FERC NOPR noted would be acceptable.
Response: Stakeholders would not be likely to have all the information required to make an informed decision. The SDT is seeking the appropriate balance between being too vague and too prescriptive. Based on comments received, the wording has been clarified to better show the SDT's intent.		

Organization	Yes or No	Question 3 Comment
2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community There is a requirement to include any mitigation plans, not a requirement to mitigate – doing nothing could be a possible plan. No change made.		
Manitoba Hydro	No	1 a. It would be very difficult to estimate the annual hours of exposure at or above a certain load level. 2 b. An assessment on the health, safety, and welfare of the community should not be part of a reliability assessment - this is purely subjective. 3 & 4. In situations where load interruption is a new proposal, historical data will not be available. What does the SDT expect here? 5. Is there a requirement to mitigate? If there is a requirement to mitigate, the required time frame is not identified.
Response: 1) Planning studies should provide the information necessary as to the Load levels at which the use of Firm Demand interruption would be required. Evaluation of annual Load profiles where the Load level is exceeded would allow estimation of the duration. No change made. 2) The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community 3 & 4) Any estimate of future performance has to be based on some sort of available historical information. Use of similarly situated lines/deliveries allows for estimation of future performance. 5) There is a requirement to include any mitigation plans, not a requirement to mitigate – doing nothing could be a possible plan.		
Ameren	No	We request that Items 5 and 7 also include information regarding estimated costs and schedule for implementation. Any permitting issues associated with the

Organization	Yes or No	Question 3 Comment
		alternatives should also be included. Any previous attempts to build facilities but were blocked should also be part of the record.
Response: Items 5 and 7 do not prohibit inclusion of cost, schedule information, or other project information and it is anticipated these issues would normally be included. The SDT is seeking the appropriate balance between being too vague and too prescriptive. No change made.		
Consolidate Edison Co. of NY, Inc.	No	See reply to Question 5
Salt River Project	No	Additional comment from SRP for Q #5.
Response: Please see response to Q5.		
City of Austin dba Austin Energy	No	Some of the information for inclusion in the Stakeholder Process is too burdensome and of limited value. In particular, 2b and 4 can be deleted because the requested information may not be available -- particularly if it is new load growth.
Response: The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community Any estimate of future performance has to be based on some sort of available historical information. Use of similarly situated lines/deliveries allows for estimation of future performance. No change made.		
LCRA Transmission Services Corporation	No	Requirement 1 only requires that the Transmission Planner provide system load data, however, assumptions about system dispatch are also relevant. Requiring load without dispatch will not provide a complete understanding of the conditions under which Footnote 12 will apply. As a reliability standard, the Transmission Planner is required to find a range of plausible system conditions under which a criteria

Organization	Yes or No	Question 3 Comment
		violation may be resolved. The requirement (1a) to provide an estimate of the exposure creates an overly burdensome requirement to investigate a wider range of possible operating conditions than is currently performed. Requirement 2a and 2b are overly burdensome on at Transmission Planner/Transmission Owner who does not directly serve retail loads by placing a requirement on the Transmission Planner/Transmission Owner to provide data that is outside of its control to develop or maintain.
Response: The SDT believes the information in Section II is sufficient and would bring out any concerns related to dispatch conditions. No change made. Planning studies should provide the information necessary for 1.a as to the load levels at which the use of Firm Demand interruption would be required. Evaluation of annual Load profiles where the Load level is exceeded would allow estimation of the duration. The SDT believes 2.a and 2.b's provision of customers affected and duration and assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording for 2.b has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community		
Duke Energy	No	In Item #8, replace the word "planners" with the words "Transmission Planners".
Response: The SDT agrees, and item 8 of Section II has been modified accordingly. 8. Assessment of potential overlapping uses of footnote 'b' including overlaps with adjacent Transmission Planners and Planning Coordinators		
Hydro-Quebec TransEnergie	No	For example, under 2 b., assessment of the impacts of interruptions on health, safety, or welfare of the community is not information that could be reasonably expected to be available to system planners. All loads may face interruptions from time to time,

Organization	Yes or No	Question 3 Comment
		and the impact on health, safety or welfare is very difficult to identify. This item should be deleted.
Georgia Transmission Corporation	No	GTC does not understand how item #2b of Section II pertains to the Transmission Planner or the Planning Coordinator. These types of assessments are beyond the scope of the Transmission Planner or the Planning Coordinator and if necessary, should possibly be done by the Load Serving Entity.GTC Recommends the SDT remove item #2b, the following sentence:"An assessment of the use of Firm Demand interruption under footnote 12 on the health, safety, and welfare of the community."
Response: Such an assessment is already required under EOP-001-2.1b by the Transmission Operator and Balancing Authority. A similar requirement for the Transmission Planner/Planning Coordinator would rely on the same type of information and sources already required under the EOP standard. The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community		
NorthWestern Energy (NWMT)	No	Comments: The estimated number and type of customers affected is not needed for reliability of the Bulk Power System. We suggest removing Item 2a in Section II of Attachment 1. An assessment of the health, safety, and welfare of the community should not be required. It is too vague and coud present legal problems. We suggest removing Item 2b in Section II of Attachment 1.
Response: The SDT believes provision of customers affected and duration and assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Such an assessment is already required under EOP-001-2.1b by the Transmission Operator and Balancing Authority. The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for		

Organization	Yes or No	Question 3 Comment
understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community		
ISO New England Inc.	No	Section II, Paragraph 2b requires "an assessment of the use of Firm Demand interruption under footnote 12 on the health, safety, and welfare of the community". A great deal of subjectivity and information that is not readily available to the Transmission Planner or Planning Coordinator would be required to accurately access the effect of load shedding on the community as required by 2b. Additionally Paragraphs II.3 and 4 require estimates of the frequency and duration of Firm Demand interruption would be difficult to provide. These requirements should be deleted. These requirements also undermine the deterministic nature of the Planning Standard. Paragraph II.2.5 that requires future plans to mitigate the need for Firm Demand Interruption should be modified to again emphasize the near term nature of single contingency non-consequential load shedding as a Planning option.
Response: Such an assessment is already required under EOP-001-2.1b by the Transmission Operator and Balancing Authority. A similar requirement for the Transmission Planner/Planning Coordinator would rely on the same type of information and sources already required under the EOP standard. The SDT believes assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording has been clarified to better show the SDT's intent. 2b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community Planning studies should provide the information necessary as to the Load levels at which the use of Firm Demand interruption would be required. Evaluation of annual Load profiles where the Load level is exceeded would allow estimation of the duration. Any estimate of future performance has to be based on some sort of available historical information. Use of similarly situated		

Organization	Yes or No	Question 3 Comment
lines/deliveries allows for estimation of future performance. No change made. A purpose of the stakeholder process is to ensure those impacted by use of Firm Demand interruption and the regulators responsible for quality of service have input on its use and the acceptability of the mitigation plan. No additional elaboration on the use of Firm Demand interruption in the standard is necessary. No change made.		
South Carolina Electric and Gas	No	See response to question #1
Response: Please see response to Q1.		
Electric Reliability Council of Texas, Inc.	No	Please see ERCOT's response to question 1 - the NERC Reliability Standards should not contain requirements related to stakeholder processes, whether they are procedural or substantive. If an exception process is retained, it should be outside of the NERC Reliability Standards (e.g. in the Rules of Procedure). ERCOT also provides the following comments on Section II - the ERCOT comments are in parentheses for easy reference and distinction relative to the proposed requirements. II. Information for Inclusion in Item #3 of the Stakeholder ProcessThe responsible entity shall document the planned use of Firm Demand interruption under footnote 'b' which must include the following: - (ERCOT COMMENT: This is all that is needed for this. The documentation would be relative to the objective criteria developed for this purpose.) 1. Conditions under which Firm Demand interruption under footnote 'b' would be necessary:a. System Load level and estimated annual hours of exposure at or above that Load levelb. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency(ERCOT COMMENT: "1" is not necessary if objective criteria are developed as benchmarks for the exception process. In that case, exceptions would only be allowed if the objective criteria were met, regardless of the underlying assumptions related to conditions and contingencies.) 2. Amount of Firm Demand MW to be interrupted with:a. The estimated number and

Organization	Yes or No	Question 3 Comment
		type of customers affectedb. An assessment of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community(ERCOT COMMENT: The considerations reflected in a and b are inappropriate for a reliability standard. Appropriate considerations for reliability standards are related to the reliability performance of the system. The considerations in a and b are more akin to quality of service issues better suited for regional policy discussions. It is not within the purview of the SDT to address those matters.) 3. Estimated frequency of Firm Demand interruption under footnote ‘b’ based on historical performance(ERCOT COMMENT: Historical performance is irrelevant. If the SDT is going to retain revisions that accommodate non-consequential load shedding, then the only relevant metrics are the objective criteria that set the benchmarks for such exceptions.) 4. Expected duration of Firm Demand interruption under footnote ‘b’ based on historical performance(ERCOT COMMENT: See ERCOT response to “3” above.) 5. Future plans to mitigate the need for Firm Demand interruption under footnote ‘b’(ERCOT COMMENT: This is redundant to the requirement in the reliability standards that requires a plan to resolve any violations identified in the planning process. Furthermore, if load shedding is allowed, this requirement doesn’t make sense. Presumably the idea behind allowing these exceptions is to obviate the prospective need for other alternatives. If that is not the case, then there is no need to allow the exceptions, because the transmission upgrades to mitigate the need for load shedding can be established in the planning horizon.) 6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’(ERCOT COMMENT: The basis for the load shedding exception is to provide a means to meet the TPL performance requirements in the context of a planning assessment. Accordingly, this is redundant to the planning assessments, the point of whichis to identify and resolve performance issues.)

Organization	Yes or No	Question 3 Comment
		7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote ‘b’(ERCOT COMMENT: Load shedding exceptions should be based on objective criteria and be reviewed pursuant to a process external to the NERC reliability standards. Alternative discussions could be part of that external process.) 8. Assessment of potential overlapping uses of footnote ‘b’ with adjacent planners(ERCOT COMMENT: It is not clear what this means. Each functional entity performs assessments relative to its own system. This appears to introduce a vague regional transmission planning requirement with no structure or rules for such assessments.)

Response: Please see response to Q1.

1. The SDT believes the information in Section II is necessary for stakeholders to understand the reason Firm Demand interruption use is appropriate and make an informed decision. No change made.

2. The SDT believes the information in section II is necessary for stakeholders to understand the reason Firm Demand interruption use is appropriate and make an informed decision. The SDT believes provision of customers affected and duration and assessment of the impact of Firm Demand interruption on the health, safety, and welfare of the community is necessary for understanding the reliability impact and for stakeholders to make an informed decision. Based on comments received, the wording for 2.b has been clarified to better show the SDT’s intent.

> 2b. Assessment of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community

3. and 4. The SDT believes the information in Section II is necessary for stakeholders to understand the reason Firm Demand interruption use is appropriate and make an informed decision. Any estimate of future performance has to be based on some sort of available historical information even for a new line/delivery. The SDT believes it is clear that for stakeholders to make an educated decision regarding Firm Demand interruption, the information must be provided for each instance of Firm Demand interruption use within the Transmission Planner/Planning Coordinator’s area. No change made.

5. The mitigation plan identifies how reliability violations will be avoided in the future where projects or other actions are not available in time or are not cost effective. No change made.

Organization	Yes or No	Question 3 Comment
6. The SDT believes the wording regarding the TPL standards is necessary to ensure the focus on meeting the TPL standard's reliability requirements is not lost and that the end state following interruption of Firm Demand meets those requirements. No change made. 7. Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. 8. The SDT believes application of a wide area view to the use of Firm Demand interruption is necessary to avoid reliability issues that would not be seen by an individual Transmission Planner/Planning Coordinator. The SDT believes assessment for Adverse Reliability Impacts is an appropriate step. However, the SDT has moved this responsibility to the ERO and deleted the Regional Entity from any involvement. Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.		
Orlando Utilities Commission	Yes	Data element 5 should probably read. "List any Future Plans or future system changes to mitigate the need for Firm Demand Interruption under footnote 'b'". There can be cases where there is no planned future project to relive the problem, or it could be expected that load will go down or changes on neighboring systems will relieve the problem.
Response: Possible future plans could include a decision not to mitigate the need for Firm Demand interruption. No change made.		

Organization	Yes or No	Question 3 Comment
LCEC (Lee County Electric Cooperative		No comment as although we are a Firm Demand customer of another entity, we have no Firm Demand / Load customers and therefore would not perform the Stakeholder Process
Arizona Public Service Company	Yes	
CPS Energy	Yes	
Essential Power, LLC	Yes	
American Electric Power	Yes	
Lincoln Electric System	Yes	
Idaho Power Co.	Yes	
Nova Scotia Power	Yes	
Response: Thank you for your support.		

4. Do you agree with the Instances for which Approval of Interruptions is required in Section III of Attachment I? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Summary Consideration: The 25 MW threshold for requiring regulatory authority review was questioned by several entities. The original 25 MW threshold came from the Registry Criteria for Load-Serving Entities. The data request showed that the average value of footnote 'b' utilization was approximately 19 MW. Therefore, the SDT has decided to leave the process threshold at 25 MW.

Several entities questioned having the 300 kV threshold for Contingencies because it has no material impact to Load and that the threshold should be based on a MW amount only. The SDT believes that the 300 kV threshold is appropriate, as the proposed TPL-001-2, which was accepted by industry and the NERC Board of Trustees, made a distinction between HV and EHV and the handling of Contingencies based on the 300 kV level. The SDT believes that the establishment of this threshold within footnote 'b' is consistent with that approach and places the proper emphasis on EHV.

Several entities had concerns that actions from a regulatory body won't happen quickly enough and that such a requirement was not appropriate for a reliability standard. There were also concerns voiced about inconsistencies in such an approach. The SDT understands these concerns and has clarified the language to assist in alleviating such concerns. The SDT also advises any entity wishing to utilize footnote 'b' in its planning process to start that process at an appropriate time so that it can be completed by the needed date.

Some concerns were raised about the role of the Regional Entity in this process. After reviewing the submitted comments, the SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency.

The following changes were made due to industry comments:

Attachment 1, Section III, first paragraph: Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b' if either:

Attachment 1, Section III, last paragraph: Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.

Organization	Yes or No	Question 4 Comment
Southwest Power Pool Reliability Standards Development Team	No	Need clarification around why the 25MWs threshold on generation was thrown into load interruption topic. Looking at the registry criteria for generation the threshold should be 20Mws for a single unit and 75 MWs for aggregated units. Not sure where the 25MWs threshold came from for generation. The 25 MW threshold in Section III is duplicative of the registration limit for generation in the ERO Statement of Compliance Registry Criteria. It is submitted for comment at this time but will not be finalized until after the above mentioned data request is complete and the final value will be submitted for industry comment and approval in the next posting. The GOP registration criteria is 20MWs. Whereas the registration criteria for LSEs and DPs is 25MWs. There appears to be some co mingling of criteria. Additionally this raises the question of whether x =25MWs. Please clarify which you intended to use. We are concerned that getting retail service regulatory authority approval in a quick manner could be difficult. We are also concerned that if it does get caught in the process of being approved and there is no time to construct, that we would not want to be found out of compliance due to something that is out of our control.

Response: The 25 MW threshold came from the Registry Criteria for Load Serving Entities, not from Generator Owners and Operators. The data request showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW.

The SDT has modified the footnote to require regulatory authority review, rather than approval. This should help alleviate some of the concerns. An entity wishing to utilize footnote "b" should start the review process at an appropriate time so that it will be completed by the required date.

> Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b' if either:

Organization	Yes or No	Question 4 Comment
Salt River Project	No	While we do agree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to give approval of the use of Firm Demand interruption under footnote ‘b’. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load.
Response: The SDT believes that the request is consistent with existing practices and is in line with an appropriate response to the Order. No change made. The 25 MW threshold came from the Registry Criteria for Load Serving Entities, not from Generator Owners and Operators. The data request showed that the average value of footnote ‘b’ utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. No change made.		
MRO NSRF	No	The NSRF suggests that Section III be removed for the following reasons. o The types of transmission projects that would be needed to avoid proposing the use of the Firm Demand interruption under footnote ‘b’ are expected to be high cost, long lead time Corrective Action projects. Therefore, consideration of the any necessary approvals from regulatory authorities or governing bodies responsible for approving the Corrective Action project is a prerequisite and essential to any discussion or stiputlations regarding disapproval of the use of footnote ‘b’ proposal. The proposed TPL-002 text for Section III does not include any language to address this crucial aspect of any footnote ‘b’ approval sipulations. o The diversity of applicable regulatory authorities and governing bodies, as well as their justicitional scope or criteria with respect to the approval of interrupt retail electic service (as well as transmission Corrective Action projects), are too diverse and complex to be appropriately addressed by proposed Approval stipulations in the

Organization	Yes or No	Question 4 Comment
		TPL-002 standard. If Section III is not removed, then the NSRF suggests the following changes. o Include the subject of approvals of Corrective Action projects that are necessary to negate the need for approval of the proposed Firm Demand interruption. o Replace the criteria regarding the voltage level of the relevant Contingency with criteria regarding the amount and type of Firm Demand that would be subject to interruption. The voltage level of the applicable Contingency elements are not material to impact on the affected load. o Replace the applicable amount of Firm Demand interruption criteria from 25 MW to at least 100 MW. There are many radial fed loads that are much geater that 25 MW and there are no stackholder meetings and required approvals for allowing the loads to be fedd radially (subject to interruption for Category B contingencies) rather than being network fed. The DOE threshold for requiring formal system event analysis is 100 MW of load dropping. So, why should the TPL-002 standard required special approvals to allow less than 100 MW of load be subject to interruption to assure BES reliability? o Change the text of "in Year One of the Planning Assessment" to "in the ten year planning horizon of the Plannign Assessment". The planning assessments may reveal that the need to use of Firm Demand interruption will occur in Year 2, Year 3 or beyond (e.g. when a significant previously unforecast load increase is forecast to occur before any needed Corrective Action project could be initiated and implemented). o The NSRF is concerned that the current wording, "Corrective Action in Year One of the Planning Assessment" could be interpreted to require an annual stakeholder process review and approval. The NSRF suggests that the standard drafting team provide some language regarding a specific period that is expected for reaffiming the approval of the Firm Demand interruption. A review interval of at least every five years should provide reasonable business certainty and allow for future transmission

Organization	Yes or No	Question 4 Comment
		construction if needed. The specific defined period of review should allow entities to operate in an effective manner. The NSRF is also concerned about the condition where approval was granted and then removed. Would an entity be instantly non-compliant to the TPL standards? If this is a possibility, the Standard Drafting Team should add a grace period that allows an entity to credibly construct a project to remain compliant.
American Transmission Company	No	ATC recommends that Section III be removed for the following reasons. o The types of transmission projects that would be needed to avoid proposing the use of the Firm Demand interruption under footnote ‘b’ are expected to be high cost, long lead time Corrective Action projects. Therefore, consideration of the any necessary approvals from regulatory authorities or governing bodies responsible for approving the Corrective Action project is a prerequisite and essential to any discussion or stipulations regarding disapproval of the use of footnote ‘b’ proposal. The proposed TPL-002 text for Section III does not include any language to address this crucial aspect of any footnote ‘b’ approval stipulations. o The diversity of applicable regulatory authorities and governing bodies, as well as their jurisdictional scope or criteria with respect to the approval of interrupt retail electric service (as well as transmission Corrective Action projects), are too diverse and complex to be appropriately addressed by proposed approval stipulations in the TPL-002 standard. If Section III is not removed, then ATC recommends the following changes. o Include the subject of approvals of Corrective Action projects that are necessary to negate the need for approval of the proposed Firm Demand interruption. o Replace the criteria regarding the voltage level of the relevant Contingency with criteria regarding the amount and type of Firm Demand that would be subject to interruption. The voltage level of the applicable Contingency elements

Organization	Yes or No	Question 4 Comment
		are not material to impact on the affected load. o Replace the applicable amount of Firm Demand interruption criteria from 25 MW to at least 100 MW. There are many radially fed loads that are much greater than 25 MW and there are no stakeholder meetings or required approvals for allowing the loads to be fed radially. The DOE threshold for requiring formal system event analysis is 100 MW. So, ATC believes the TPL-002 standard should not require special approvals to allow less than 100 MW of load to be interrupted to assure BES reliability. o Change the text of "in Year One of the Planning Assessment" to "in the ten year planning horizon of the Planning Assessment". The planning assessments may reveal that the need to use of Firm Demand interruption will occur in Year 2, Year 3 or beyond (e.g. when a significant previously unexpected load increase is forecast to occur before any needed Corrective Action project could be initiated and implemented). o ATC is concerned that the current wording, "Corrective Action in Year One of the Planning Assessment" could be interpreted to require an annual stakeholder process review and approval. ATC suggests that the standard drafting team provide some language regarding a specific period that is expected for reaffirming the approval of the Firm Demand interruption. A review interval of at least every five years should provide reasonable business certainty and allow for future transmission construction if needed. The specific defined period of review should allow entities to operate in an effective manner.

Response: If you have already gotten approval from regulatory bodies in your planning process, then Section III is basically already accomplished, and carrying out the remaining details should not be burdensome. No change made.

While it may be true that regulatory authorities and governing bodies are diverse and complex, they are representing their area of responsibility. What may be acceptable in one area, may not be acceptable in another. This is determined by the appropriate authorities. No change made.

The SDT does not believe approvals from regulatory authorities or governing bodies responsible for approving the Corrective Action project is a prerequisite or essential. The focus of this portion of the standard is dropping Load and when approval is necessary.

Organization	Yes or No	Question 4 Comment
There is no benefit in including approval of Corrective Actions. No change made. The proposed TPL Standard (TPL-001-2) makes a distinction in the requirements based on the voltage level of the Contingency studied. This is based on the belief that transmission lines 300 kV and above are for bulk power transfers, and lower voltage lines are more for Load serving. The SDT believes that when a higher voltage line Contingency causes the need for Load dropping, it should require approval. No change made. The data request also showed that the average value of footnote ‘b’ utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. No change made The text regarding Year One of the Planning Assessment just means that approval from the appropriate regulatory bodies is needed at least one year before that Load shed is planned for. This does not mean that the need for dropping Load cannot be determined in the study of a future year or that approval cannot be sought sooner. The intent of the SDT was that a review must be obtained one time from the appropriate regulatory body. It does not need to be reviewed again unless the situation changes. The SDT has changed the wording to the following: Before a Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote ‘b’ if either: The proposed TPL-001-2 accommodates this concern regarding circumstances beyond the control of the Transmission Planner or Planning Coordinator in Part 2.7.3 of Requirement R2.		
SERC EC Planning Standards Subcommittee	No	We recommend using a technical basis for load shedding instead of a Stakeholder Process. However, if a Stakeholder Process is used, the approval thresholds are correct. The Stakeholder Process should not even be initiated for less than these threshold levels.
Southern Company	No	Southern recommends using a technical basis for load shedding instead of a Stakeholder Process. However, if a Stakeholder Process is used, the approval thresholds given in the draft seem appropriate. Furthermore, we believe the Stakeholder Process should not even be initiated for less than these threshold levels.

Organization	Yes or No	Question 4 Comment
		Lower amounts of load and lower voltage contingencies do not need to be taken through a Stakeholder Process.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.		
ACES Power Member Standards Collaborators	No	(1) What is the justification for selecting a 300 kV contingency as a threshold for requiring local regulatory agency approval? What if the planned load shed is only for 1 MW? If a threshold is required, we think it should be based on load size rather than contingency size? (2) What is the justification for selecting 25 MW of planned firm load interruption as a threshold for requiring local regulatory approval? The threshold could be set based off of the accompanying Section 1600 data request. Since there are likely not many instances, it could be required for any new instance that exceeds the existing planned load shed amounts. Thus, the threshold would be set just above existing planned load interruptions. (3) A disclaimer should be added to clarify that an entity may still have to seek local regulatory agency approval per the local regulatory agency's rules. Nothing in the NERC standard will change the local regulatory agency's rules. (4) What if the local regulatory agency does not want to address the planned load

Organization	Yes or No	Question 4 Comment
		shed in the planning time frame? What is the Transmision Planner required to do? While it is likely a local regulatory agency would be interested in addressing a planned load interruption, nothing in the NERC or Commission rules can compel a local regulatory agency to address such matters in a specific time frame. (5) Bullet 1.a is confusing. Is it intended to say that if two Elements are part of a contingency and the Elements have different voltage classes, the Element with the lowest voltage class must exceed the 300 kV threshold? If this is the case, the bullet needs further clarification because it does not state this clearly. (6) The first paragraph after section III appears to contradict bullets 1 and 2. Bullets 1 and 2 place contingency and load thresholds on the planned firm load interruption. However, this paragraph says that the regulatoy body responsible for retail electric service must approve the planned load shed before it can be used in Year One of the planning assessment. If the purpose is for the thresholds to apply beyond Year One and any instance in Year One to require approval, then the language regarding the thresholds needs to clarify that the thresholds apply beyond Year One only. (7) We think it is redundant for the Regional Entity to evaluate planned interruptions of firm load in its footprint. The Planning Coordinator has a wide area view and is already required to do this for its footprint. The Planning Coordinator already works with its neighbors to evaluate impacts. Requiring this evaluation by the Regional Entities is arbitrarily based on historical and political boundaries. Many Planning Coordinators have views that are broader than the Regional Entity view because they are in multiple regions. If this evaluation will be required on a regional basis, why won't it be required on an interconnection? (8) The evaluation required by the Regional Entity may be completed before planned load interruption is approved by local regulatory body. The TP and PC must submit the data based on their plan before the local regulatory body approves the planned load interruption. The Regional Entity must complete its evaluation within 45 days of receiving the information. There is no obligation for the local regulatory body to act within 45 days. Wouldn't it make more sense to evaluate the planned load shed after

Organization	Yes or No	Question 4 Comment
		it is approved by the local regulatory body?

Response: (1) The proposed TPL Standard (TPL-001-2) makes a distinction in the requirements based on the voltage level of the Contingency studied. This is based on the belief that Transmission lines 300 kV and above are for bulk power transfers, and lower voltage lines are more for Load serving. The SDT believes that when a higher voltage line Contingency causes the need for Load shed, it should require approval even if it is only 1 MW.

(2) The data request showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. No change made.

(3) There is no need for such a disclaimer in a NERC Standard. An entity has to abide by other applicable rules outside of the standard. No change made.

(4) The SDT has modified the footnote to require regulatory authority review, rather than approval. This should help alleviate some of the concerns. If the local regulatory agency does not want to address the planned Load shed, then they are giving their tacit approval to the Load shedding.

> Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b' if either:

(5) Yes. For 1.a to apply, the Element with the lowest system voltage level must be 300 kV or above. The SDT believes the wording is clear. No change made**.**

(6) The text regarding Year One of the Planning Assessment just means that approval from the appropriate regulatory bodies is needed at least one year before that Load shed is planned for. This does not mean that the need for dropping Load cannot be determined in the study of a future year or that approval cannot be sought sooner.

(7) The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency.

> Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of

Organization	Yes or No	Question 4 Comment
whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption. (8) No. The planned Load shed should not be reviewed by the local regulatory body unless it has been determined that there are no Adverse Reliability Impacts.		
Bonneville Power Administration	No	Regarding Section III.2 as stated above, BPA does not support quantitative limits on planned interruption, as planners generally do not plan the system to interrupt demand for a single contingency. Setting a quantitative limit would push transmission planners to plan the system to meet such a limit for a single contingency in all cases.
Response: The SDT does not agree that setting a quantitative limit would push Transmission Planners to plan the system to meet such a limit for a single Contingency in all cases. The footnote states that an objective of the planning process should be to minimize the likelihood and magnitude of Load shed. However, a quantitative limit is needed to ensure that unreasonable amounts of Load shed are not proposed. No change made.		
TVA Transmission Reliability Engineering & Controls	No	Please see answer to question #1. TVA believes that the requirements of 25 MW as well as any Bulk contingency over 300-kV is much too burdensome. TVA beleives that only larger load drops should require a Stakeholder review.
Response: Please see response to Q1.		
Arizona Public Service Company	No	AZPS does not agree that approval by the Regional Entity should be required. Once the process has been fully vetted by the stakeholders, including the regulatory authority for retail service, there is absolutely no need for Regional Entity approval. There would be no adverse affect of non-consequential load tripping on the BES. No reason for Reginal Entity involvement.
Response: The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency.		

Organization	Yes or No	Question 4 Comment
Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.		
BrightSource Energy, Inc. Los Angrles Department of Water and Power Deseret Generation & Transmission Cooperative California Independent System Operator nevada power company dba nvenergy PG&E Company Modesto Irrigation Districtt Utility System Efficiencies, Inc.	No	While we do not disagree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to approval of the use of Firm Demand interruption under footnote 'b'. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load. Requiring the Regional Entity to approve the Non-Consequential Load Loss under footnote b in TPL-002 (Footnote 12 in TPL-001-3) is duplicative and would increase the work load of the Regional Entities without improving reliability. The TP and PC are already required to make available to the affected stakeholders, verification that TPL Reliability Standards performance requirements will be met following the application of footnote 'b' (see Section II.6) and the assessment of potential overlapping uses of footnote 'b' with adjacent planners" (see Section II.8), it is hard to imagine what type of review and verification is required to show that "there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity's footprint".
Response: The SDT believes that the request is consistent with existing practices and is in line with an appropriate response to the Order. No change made. The 25 MW threshold came from the Registry Criteria for Load Serving Entities, not from Generator Owners and Operators. The data request showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. No change made.		

Organization	Yes or No	Question 4 Comment
The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency. Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote ‘b’, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption.		
MISO	No	We generally agree with the instances for which approval or interruptions is required, but do not agree with the requirement to seek regulatory approval.In general, when the footnote is proposed to be utilized as an interim measure until transmission facilities can be added or reinforced, regulatory approval must be sought in advance. Having this requirement in a reliability standard not only is unnecessary, but also introduces regulatory requirements (which provides no reliability benefit or basis) in a reliability standard. NERC reliability standards should focus only on BES reliability, not any regulatory requirements. Section III should therefore stipulate a high-level requirement for the proposing entity to submit the proposal to the RE for review and concurrence. Along with the submission, the RE may require the proponent to include a copy of appropriate regulatory approval (which the entity should have already obtained). The conditions (1) and (2) for seeking regulatory approval can be retained, but now become the criteria for seeking review and concurrence by the RE. Additionally, Attachment 1 requires that the ERO develop a methodology on evaluation criteria to be published for determining Adverse Reliability Impacts for approval by the ERO. Planning Assessments are performed on an annual basis. The Attachment 1 process and ERO methodology may require a lengthy approval process that must be repeated on an annual basis.
Response: The SDT has modified the footnote to require regulatory authority review rather than approval. This should help alleviate some of the concerns. Before a Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority		

Organization	Yes or No	Question 4 Comment
or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote ‘b’ if either: The SDT has added language to indicate that the Stakeholder Process does not have to be repeated for each annual assessment if the process has confirmed for a specific project that it is acceptable to curtail a Firm Demand, provided that the parameters have not changed. If any changes have occurred to the original parameters, these issues must then be addressed in the Stakeholder Process before that Planning Assessment can be completed. An entity does not have to repeat the stakeholder process for a specific application of footnote ‘b’ utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.		
Essential Power, LLC	No	This solution requires filing with a regulatory body for any extra interruptions. This seems to be a lot of effort and language for a contingency event that the system is supposed to be able to handle.
Response: The SDT believes that the stakeholder process is necessary to ensure that Load shed is utilized for single Contingencies only under limited circumstances. No change made.		
Tacoma Power	No	As noted in our response to question 2, regulatory approval is often a slow process and is not conducive to repeating annually. Instead of a 25 MW limit, a 300 MW limit that corresponds to the reporting level of firm demand in EOP-004 is more appropriate.
Response: The SDT has added language to indicate that the Stakeholder Process does not have to be repeated for each annual assessment if the process has confirmed for a specific project that it is acceptable to curtail a Firm Demand, provided that the parameters have not changed. If any changes have occurred to the original parameters, these issues must then be addressed in the Stakeholder Process before that Planning Assessment can be completed. An entity does not have to repeat the stakeholder process for a specific application of footnote ‘b’ utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.		

Organization	Yes or No	Question 4 Comment
The data request showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW.		
Manitoba Hydro	No	The Section III states that regulatory authority approval is required for interruptions over 25 MW or if voltage level of the contingency is greater than 300 kV. However, a regulatory authority cannot approve interruption of Firm Demand unless it already has such jurisdiction that is conferred upon them by legislation. A reliability standard cannot confer that jurisdiction. Further, the regulator is already part of the proposed stakeholder group and will have input into the proposal. The Section III requires the Regional Entity to review the proposed use of Firm Demand interruption under footnote 'b'. What impact does it have on the Regional Entity to necessitate a review, if the stakeholders have already agreed to a process, TPL Reliability Standards performance requirements have been verified as in Section II.6, and potential overlapping uses have been assessed with adjacent planners as in Section II.8. What criteria will the Regional Entity use to make their assessment of Adverse Reliability Impacts and potential cumulative effects given the above TPL performance must be met? This requirement can lead to inconsistent decisions between regions.
Response: The SDT believes that the request is consistent with existing practices and is in line with an appropriate response to the Order. No change made. The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency. Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.		

Organization	Yes or No	Question 4 Comment
Independent Electricity System Operator	No	We generally agree with the instances for which approvals or interruptions are required. Approval is to be granted by the Reliability Coordinator or applicable reliability authority. (1) In general, when the footnote is proposed to be utilized as an interim measure until transmission facilities can be added or reinforced, regulatory approval must be sought in advance. Having this requirement in a reliability standard not only is unnecessary, but also introduces regulatory requirements (which provides no reliability benefit or basis) in a reliability standard. NERC reliability standards should focus only on BES reliability, not any regulatory requirements. Section III should therefore stipulate a high-level requirement for the proposing entity to submit the proposal to the Reliability Coordinator for review and concurrence. The conditions (1) and (2) for seeking explicit regulatory approval can be retained, but now become the criteria for seeking review and concurrence by the applicable reliability authority. (2) We suggest deleting Item 1 in the first paragraph (with its a and b bullets) and just indicating that planned Firm Demand interruption requires approval if it is greater than 25 MW (or other threshold). Requirements for approval of the use of Firm Demand interruption should be independent of the voltage level of the contingency. (3) We propose deleting the sentence in the second paragraph “In no case can the planned Firm Demand interruption under footnote ‘b’ exceed ‘x’ MW”. A fixed limit on the allowable size of Firm Demand interruption can not be technically justified for the whole continent and each case should be assessed to determine if its impact on reliability of the bulk transmission system is acceptable or not. The impact of each case on the affected customers (economic, welfare, etc.) will also be reviewed and approved by the regulatory authority or governmental body of each jurisdiction and a “reliability” standard must not impose limits and restrictions pertaining to these aspects. (4) The third paragraph proposes that the Regional Entity should review each case of Firm Demand interruption and verify that there are no Adverse Reliability Impacts.

Organization	Yes or No	Question 4 Comment
		We propose instead that the transmission planner or planning coordinator study the BES performance requirements and the reliability impacts of Firm Demand interruption, including its correct operation, miss-operation, and the failure to operate. The transmission planner should then submit a report of this assessment to the Reliability Coordinator for review and approval.
Response: (1) Regulatory review is not always sought in advance. The SDT believes this review is necessary when the planned Load shed exceeds either of the thresholds in Section III. No change made. 2) The proposed TPL Standard (TPL-001-2) makes a distinction in the requirements based on the voltage level of the Contingency studied. This is based on the belief that transmission lines 300 kV and above are for bulk power transfers, and lower voltage lines are more for Load serving. The SDT believes that when a higher voltage line Contingency causes the need for Load shed, it should require approval even if it is only 1 MW. No change made. (3) The SDT does not agree with this suggestion, as such an important consideration cannot be left open-ended. Order 762 also pointed out the need for a limit on this threshold value. The Order 762 data request showed that there were no utilizations of footnote 'b' involving more than 75 MW. Based on this fact, and after reviewing other aspects of the data, the SDT has set the proposed ceiling on footnote 'b' utilization at 75 MW. (4) The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency. Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.		
Ameren	No	We do not believe that section III is needed, and particularly if an approval is included as part of the section I process. We do not subscribe to dropping Firm Demand (non-consequential load) for single contingency events, and do not see a need to include a voltage threshold as part of the contingency requirements. All single contingencies in Category B should be

Organization	Yes or No	Question 4 Comment
		applicable.
Response: Section 3 directly addresses concerns raised by FERC contained in the remand of the TPL standard. Items 1 and 2 are included to further define and "put a box" around the situations where first Contingency Load shedding could be employed. Having the ERO review the application of footnote 12 will provide needed continent-wide consistency. The proposed TPL Standard (TPL-001-2) makes a distinction in the requirements based on the voltage level of the contingency studied. This is based on the belief that transmission lines 300 kV and above are for bulk power transfers and lower voltage lines are more for Load serving. The SDT believes that when a higher voltage line Contingency causes the need for load dropping, it should require approval even if it is only 1 MW. No change made.		
ReliabilityFirst	No	ReliabilityFirst has a major issue/concern with Attachment 1, Section 3 (specifically the last paragraph regarding approval). This section requires the Regional Entity to review each proposed use of Firm Demand interruption under footnote 12 in order to verify that there are no Adverse Reliability Impacts. The paragraph goes on to require the Regional Entity to make its determinations and evaluation of Adverse Reliability Impacts using a published methodology approved by the ERO. First, since the Regional Entity is not a user, owner or operator of the BES, ReliabilityFirst believes the Regional Entity should not have requirements placed upon them. Furthermore there is no guidance on what is required to be placed within the published methodology. ReliabilityFirst believes this verification is outside the Regional Entity scope as delegated by the ERO. ReliabilityFirst believes that if such verification by the Regional Entity is required, it should be specifically laid out in the NERC Rules of Procedure and not an attachment within a standard.
American Electric Power	No	AEP is concerned that not all Regional Entities are the same in regards to their engineering and planning staff, and is not confident that they would all have the resources necessary to perform the required analysis. AEP is concerned by any attempt to require that a Regional Enity adhere to processes and prodecures that have not yet been established. FERC has made comments in the past regarding requirements places upon regional entities (RRO), and while this standard does not

Organization	Yes or No	Question 4 Comment
		yet apply, is does indirectly obligate them to rules and procedures not yet established.
Response: The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency. Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.		
Consolidate Edison Co. of NY, Inc.	No	See reply to Question 5
Salt River Project	No	Additional comment from SRP for Q #5.
Response: Please see response to Q5.		
City of Austin dba Austin Energy	No	The 25 MW threshold for Approval of Interruptions of Firm Demand under Footnote 'b' is too low. It should be increased to 50 MW because there is an elaborate Stakeholder process to work through the reliability concerns.
Response: The data request showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. No change made.		
Lincoln Electric System	No	For item 1(b) in Section III, LES requests that the drafting team clarify why approval by the regulatory authority for a generator contingency is based on the high-side voltage of the GSU rather than the generator capacity. LES believes the generator capacity, rather than the high-side voltage of the GSU, provides a more consistent basis for determining necessity for approval from the applicable regulatory authority or governing body. Additionally, LES asks for further clarification as to whether the steps referenced for

Organization	Yes or No	Question 4 Comment
		Year One of the Planning Assessment extend to Year Two and beyond.
Response: The SDT disagrees that generator capacity is a better basis for determining the necessity for review. The requirements within the TPL standards have different performance levels based on a 300 kV voltage threshold for the Contingency. This distinguishes Facilities generally constructed to transmit power from Facilities used to distribute power to Load centers. The SDT believes this to be a better basis for determining what is important enough to require review from regulatory authorities. No change made. The text regarding Year One of the Planning Assessment just means that review from the appropriate regulatory bodies is needed at least one year before that Load shed is planned for. This does not mean that the need for dropping Load cannot be determined in the study of a future year or that review cannot be sought sooner.		
LCRA Transmission Services Corporation	No	See previous comments about use of the term “Firm Demand”.
Response: Please see previous response.		
Tri-State Generation & Transmission Association, Inc.	No	We disagree with the instances for which Approval of Interruptions is required as proposed by Section III of Attachment I. TPs will develop plans to mitigate BES performance violations, but those plans may not be able to be constructed in time. The reason being that the time required to construct a project to mitigate the issues can take several years. This is due to the need for public input, permitting, acquisition, and construction. Attachment I does not allow planners to design temporary mitigation to accommodate real world construction issues, which are often complex in nature due to competing interests. Attachment I also states that “Before a Firm Demand interruption under footnote ‘b’ is allowed to be utilized as an element of a Corrective Action Plan in Year One of the Planning Assessment...” The need for approval seems burdensome such that it does not allow for temporary mitigation to meet BES performance criterion while other avenues are explored and vetted. The intent of Section III is genuine, but we feel that it is over-reaching for a NERC

Organization	Yes or No	Question 4 Comment
		Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to approval of the use of Firm Demand interruption under footnote 'b'. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load.
Response: The SDT has modified the footnote to require regulatory authority review, rather than approval. This should help alleviate some of the concerns. An entity wishing to utilize footnote "b" should start the review process at an appropriate time so that it will be completed by the required date. Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b' if either: Section III is not requiring action from the regulatory authority. It requires action from the Transmission Planner or Planning Coordinator. The 25 MW threshold came from the Registry Criteria for Load Serving Entities, not from Generator Owners and Operators. The data request showed that the average value of footnote 'b' utilizations was 19 MW. Therefore, the SDT has kept the process threshold at 25 MW. No change made.		
Duke Energy	No	Section III is confusing. Are the last two paragraphs of Attachment 1 supposed to be part of Section III? These paragraphs, when read in combination with the first paragraph of Attachment 1, seem to say that any time a Firm Demand interruption using footnote 'b' or footnote 12 shows up in the Near-Term Transmission Planning Horizon, the Stakeholder Process must be invoked. It would seem more reasonable to invoke the Stakeholder Process only when such interruption occurs in Year One of

Organization	Yes or No	Question 4 Comment
		the Planning Assessment.
Response: The last two paragraphs are intended to be included in Section III. The SDT believes it is more appropriate to require the stakeholder process whenever load interruption is planned in the Near-Term Transmission Planning Horizon. That allows more time for all interested parties to be informed.		
Hydro-Quebec TransEnergie	No	For example, in 1a., it is not clear what is meant by "the stated performance criteria regarding allowances...". Why is it necessary to give this kind of explanation? In 1b., the use of the term "non-generator step up transformer" is unusual. Suggest rewording 1b to read:For a generator or generator step up transformer outage Contingency, the extra high voltage (EHV) limit applies to the BES connected voltage (high-side of the Generator Step Up transformer). For any other transformer outage Contingency, the EHV limit applies to the low-side winding (excluding tertiary windings).
Response: In the context of the complete sentence, the SDT believes that the comment is clear. No change made. The terminology is consistent with the Board of Trustees approved TPL-001-2. No change made.		
NorthWestern Energy (NWMT)	No	Comments: A NERC Standard should not require action from a regulatory authority to approve the use of Firm Demand interruption. There is too much diversity in regulatory authorities over the industry-wide area. This would increase the work load of the Regional Entities without improving reliability. We suggest removing Section III of Attachment 1.
Response: The SDT has modified the footnote to require regulatory authority review, rather than approval. This should help alleviate some of the concerns.. Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under		

Organization	Yes or No	Question 4 Comment
footnote 'b' if either: Section 3 directly addresses concerns raised by FERC contained in the remand of the TPL standard. Items 1 and 2 are included to further define and "put a box" around the situations where first Contingency Load shedding could be employed. The SDT believes that an evaluation by the ERO of the potential for adverse system impacts is needed to provide continent-wide consistency. Therefore, Section III is needed**.** No change made.		
Georgia Transmission Corporation	No	GTC would appreciate if the SDT could please clarify if the approval of a regulatory authority or governing body is referring to the Regional Entity.The first sentence in Section III:"Approval of the use of Firm Demand interruption under footnote 12 by the applicable regulatory authority or governing body responsible for retail electric service issues is required if either:..."
Response: No, that sentence refers to regulatory authorities such as a state public service commission.		
ISO New England Inc.	No	Section III describes the instances where Approval of Interruptions of Firm Demand are required under footnote 12. It is not clear whether under Paragraph III.1.a and Paragraph III.1.b the Transmission Planner is to base the determination on either contingency or both contingencies i.e. is "and" logic to be applied or is "or" logic used? Paragraph III.2 requires such approval for interruption equal to or greater than 25 MW, this is a very small amount of load to be required to bring to a stakeholder approval process for second contingency events. This amount should be increased to at least 100 MW. Additionally in Section III, it is not clear who the "regulatory authority or governing body responsible for retail electric service issues" is. Having this requirement in a reliability standard not only is unnecessary, but also introduces regulatory requirements in a reliability standard. NERC reliability standards should focus only on BES reliability, not any regulatory requirements. The Attachment goes on to state "The Regional Entity determinations of Adverse Reliability Impacts are to be evaluated by the Regional Entity through a published methodology approved by the ERO". This is essentially a "fill in the blank" requirement and makes it necessary to

Organization	Yes or No	Question 4 Comment
		comment and approve the footnote attachment without the benefit of reviewing a proposed methodology.
Response: Section 3 clarifies the criteria for the application of footnote 12. Items 1 and 2 are included to further define and "put a box" around the situations where first Contingency Load shedding could be employed; as such, they are an "or" requirement and the 'or' has been added to the Attachment. The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency. Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption. The regulatory or governing body should be known by the entity who plans to use footnote 12.		
South Carolina Electric and Gas	No	See response to question #1
Response: Please see response to Q1.		
Electric Reliability Council of Texas, Inc.	No	If non-consequential load shedding is allowed for single contingency conditions, as discussed above, it should be based on objective critieria. As such, there is no need for the proposed stakeholder process, including the Section III instances requiring regulatory approval. As with the other stakeholder process sections, that section should be eliminated.
Response: Industry and the NERC BOT have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The SDT is now attempting to address FERC's concern expressed in their Remand Order 762 that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process, is vague, unenforceable, and not responsive to the previous Commission directives on this matter. The draft		

Organization	Yes or No	Question 4 Comment
posted for comment adds detail and specificity to the already-approved approach. The SDT does not believe it appropriate to move away from the industry and BOT approved Stakeholder Process approach. No change made. Section 3 directly addresses concerns raised by FERC contained in the remand of the TPL standard. Items 1 and 2 are included to further define and "put a box" around the situations where first Contingency Load shedding could be employed. The SDT believes that an evaluation by the ERO of the potential for adverse system impacts is needed to provide continent-wide consistency. Therefore, Section III is needed. No change made.		
San Diego Gas & Electric	No	
Public Utility District No. 1 of Snohomish County	No	
Response: Without specific comments, the SDT is unable to respond.		
Orlando Utilities Commission	Yes	Comment #1: The maximum threshold should be in the Footnote, not in the Attachment. Comment #2: I think the role identified for the Regional Entity is appropriate. Comment #3: I like the concept that regulatory approval is not required until year one. However I think either the ordering of language or the formatting needs to be changed to make it clear that the year one applies to only those that need regulatory approval. Maybe change the section to read... "Section IIIFirm Demand Interruptions under footnote 'b' that meet either or both of the criteria below are required to have approval by the applicable regulatory authority or governing body responsible for retail electric service issues. The regulatory approval is required prior to the use of that remedy in Year One of a Corrective Plan in the Planning Assessment. (Existing 1 & 2)(Existing RE Review)
Response: The maximum threshold is the last sentence of the footnote, and is also cited in Section III of the Attachment. No change made.		

Organization	Yes or No	Question 4 Comment
The SDT agrees and has deleted the Regional Entity role in this process. The oversight role, which is required in the Order, is now placed on NERC as the ERO. This change should help to promote continent-wide consistency. Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption. The SDT has modified the footnote to require regulatory authority review, rather than approval. This should help alleviate some of the concerns. An entity wishing to utilize footnote "b" should start the review process at an appropriate time so that it will be completed by the required date. Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b' if either:		
LCEC (Lee County Electric Cooperative		No comment as although we are a Firm Demand customer of another entity, we have no Firm Demand / Load customers and therefore would not perform the Stakeholder Process
CPS Energy	Yes	
Idaho Power Co.	Yes	
Nova Scotia Power	Yes	
Response: Thank you for your support.		

5. **If you have any other comments on this Standard that you haven't already mentioned above, please provide them here.**

Summary Consideration: Many commenters proposed changes to the applicable planning events for which footnote 12 applies in the new proposed TPL-001-2a standard. The SDT clarifies that the planning events for which footnote 12 are applicable were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011) in its consideration of TPL-001-2. The proposed changes are outside the scope of this project, which aims to clarify the stakeholder approval process.

Some commenters indicated confusion surrounding changes made to footnote 12 and Attachment 1 in the proposed TPL-001-2a standard in regard to the use of the term Firm Demand interruption. The SDT acknowledges that the references to Firm Demand Interruption should reference Non-Consequential Load Loss in footnote 12. The SDT has made revisions to the TPL-001-2a Footnote 12 and Attachment I to show these changes.

Some commenters continue to weigh-in on FERC's jurisdiction in regard to continuity of service to Load. FERC Order 762, beginning at Paragraph 23, discusses FERC's position on jurisdictional issues. This topic was well-vetted in the development of TPL-001-2, and FERC's subsequent NOPR and is beyond the scope/authority of this drafting team.

The following change was made due to industry comments:

Effective date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

Attachment 1 – Section I, last paragraph: An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

Attachment 1, Section III, last paragraph: Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.

Organization	Yes or No	Question 5 Comment
NorthWestern Energy (NWMT)		Comments: Footnote 12 should be added to Category P2 Single Contingency Event 2, Bus Section Fault, and to Category P2 Single Continency Event 3, Internal Breaker Fault , for EHV in the Non-Consequential Load Loss column.
Response: The planning events for which footnote 12 are applicable within the proposed TPL-001-2 standard were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011). The proposed changes are outside of the scope of this project, which aims to clarify the stakeholder approval process. No change made.		
ACES Power Member Standards Collaborators		(1) The standard needs to allow more flexibility regarding the use of planned load shed to address transmission performance issues in the planning horizon. It needs to recognize that these planned load shedding events may only be preliminary decisions for addressing problems that are several years away. If there is little chance that the planned shed load will ever be relied upon in the operating time horizon, there should be much less stringent requirements. For instance, if a PC or TP relies on planned load shed for year five of the planning horizion but year one does not utilize the planned load shed, they have four years to develop another solution. Why should great effort and resources be expended in year five when another solution will likely be developed? (2) This standard does not consider if the local regulatory body will act in time to approve the use of planned Firm Demand interruption. We believe the standard needs to consider that the Planning Coordinator and Transmission Planner may not be able to control the timelines of local regulatory agencies. As long as the PC and TP have done their part by submitting the data, they should be able to rely on the planned Firm Demand interruption until the local regulatory body acts. If the planned Firm Demand interruption is not approved, then the TP and PC should be given more time to address the transmission performance deficiency. (3) Several terms are used for the use of planned load shed. Non-consequential load loss and Firm Demand interruption are two examples. We suggest using one term consistently throughout the standard.

Organization	Yes or No	Question 5 Comment
Response: (1) For reasons similar to those raised by the commenter, the SDT limited Attachment 1 as being applicable only to planned use of Firm Demand interruption in the Near-term Planning Horizon (Years 1-5), recognizing that plans may change. The SDT believes it is appropriate to require the stakeholder approval process in the Near-term Planning Horizon. The Near-term Planning Horizon plans should become more stable over those identified on the Long-term Planning Horizon. No changes made. (2) The SDT has clarified the language concerning regulatory approval to show that review is what is actually required. Review by the regulatory authority or governing body responsible for retail electric service issues is only required in certain instance of planned Firm Demand interruption and if planned for use in Year One of the Near-Term Transmission Planning Horizon. When required, the indicated review must be obtained before it can be part of a Corrective Action Plan. Until such review, the planner would need to consider and list alternate Corrective Action Plans within its assessment. The SDT has also clarified that such reviews need only be done once, unless material changes have taken place. The SDT believes that these changes should alleviate the majority of lead-time concerns, although an entity should always build sufficient time for the process to play out into its planning cycle. (3) An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application. (4) Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption. **(5)** The terms used are appropriate since the existing FERC-approved TPL standards and the proposed TPL-001-2 (NERC Board of Trustees approved 8/4/2011) use differing terminology for the common topic (planned load shed) of both footnote 'b' (Firm Demand Interruption) and footnote 12 (Non-Consequential Load Loss). The SDT acknowledges that the reference to Firm Demand Interruption should reference Non-Consequential Load Loss. The SDT has made appropriate revisions to proposed TPL-001-2a, Attachment I.		
Independent Electricity System Operator		(1) We'd like to reiterate our support for allowing load interruption for a single contingency with sufficient review/oversight and under acceptable conditions,

Organization	Yes or No	Question 5 Comment
		including no adverse impact on the reliability of the bulk electric system. The reliability aspects (BES performance requirements) should be reviewed/approved by the Reliability Coordinator. However, issues pertaining to economics or externalities which may not be directly reliability-related are always available for review and debate by the stakeholders via the regulatory processes and subject to approval by the regulatory authority of each jurisdiction (particularly those in Canada and Mexico). (2) Furthermore, we request that Table 1 of TPL-001-3 (previous TPL-001-2 approved by NERC BOT) be corrected for EHV contingencies in P2, P4 and P5 categories to allow the same load interruption that is allowed for the related P1 contingency. Table 1 currently does not allow any load to be interrupted for an EHV single contingency if the primary circuit breakers fail to clear the fault (Category P4, "Fault plus stuck breaker"). But if load X is allowed to be interrupted for a single EHV transmission line contingency (Category P1), it should be allowed to interrupt the same load X if the primary breaker fails and the fault is cleared by other breakers. Similarly, if the same breaker has an internal fault or there is a fault on the same bus section (Category P2) or there is a failure of a relay (Category P5), which results in the loss of the same EHV transmission line, it should be allowed to interrupt the same load X. (3) We suggest that NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve them. Accordingly, we believe that the focus of the foot note 'b' should be that interruption of load must not adversely impact the reliability of the interconnected BES because reliability of supply to load and/or supply continuity is mandated by the jurisdictional authority. (4) We submit that the scope of NERC's mandatory standards does not extend to assessing or setting requirements for non-jurisdictional entities, unless such facilities are necessary for the operation of the interconnected BES or have an adverse impact on its reliability. For Canadian entities there are regulatory requirements and processes under the purview of the relevant regulatory authorities that we believe are adequate. Accordingly, customer interests are protected and are not subject to

Organization	Yes or No	Question 5 Comment
		unilateral decisions of the transmission planner. In all cases, steps are taken at the planning, design, and operations stages of system development such that non-consequential Firm Demand interruption would not adversely impact the BES and the affected customer has been given the opportunity to avail themselves of other options under the transmission development rules in the relevant jurisdictions. (5) The requirements of the footnote (including attachment) will amount to a mandate to construct additional transmission which is inconsistent with Section 215 (i) (2) of the US Federal Power Act which specifically does not authorize the ERO “to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services. (6) We suggest that NERC should not include and/or address load reliability or load supply continuity requirements within the BES Reliability Standards. In Canada, these requirements and approvals are with relevant reliability or regulatory authority. If NERC feels obligated to include such requirements for load reliability issues in US, then we propose that non-jurisdictional entities must be exempted from these requirements similar to the provisions in NUC 001. (7) The proposed implementation plan conflicts with Ontario regulatory practice respecting the effective date of the standard. It is suggested that this conflict be removed by appending to the implementation plan wording, after each “applicable regulatory approval” in the Effective Dates Section A5 of both draft standards, to the following effect: “, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.”

Response:

(1) The SDT thanks you for your general support of the proposed stakeholder process. It’s anticipated that the Reliability Coordinator will be a stakeholder participant and could raise any concerns they believe are warranted. The SDT appropriately set the BES reliability approval to the Regional Entity with ERO backstop authority per FERC Order 762, Par. 55. Paragraph 55 states in part: “NERC and the Regional Entities provide both objectivity in the decision-making process as well as the necessary

Organization	Yes or No	Question 5 Comment
reliability-focused expertise." No change made. (2) The planning events for which footnote 12 is applicable within the proposed TPL-001-2 standard were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011). The proposed changes are outside of the scope of this project which aims to clarify the stakeholder approval process. No change made. (3) The proposed Attachment 1 achieves the view stated by the commenter. BES Reliability is assured by the Regional Entity and ERO where warranted. The approval by the regulatory authority or governing body responsible for retail electric service issues addresses continuity of service to end-use Load. No change made. (4) The proposed Attachment 1 process appropriately sets governance for both the ERO and Regional Entities to ensure no Adverse Reliability Impact of the BES. If existing processes are already in place to ensure end-use Loads are appropriately protected, those processes may be utilized to fulfill the Attachment I obligations. No changes made. (5) FERC Order 762, beginning at Paragraph 23 discusses the FERC's position on jurisdictional issues that are raised by the commenter. This topic was well-vetted in the development of TPL-001-2 and FERC's subsequent NOPR and is beyond the scope/authority of this drafting team. No changes made. (6) There are no current exemptions in the TPL standards, and it is not within the scope of the SDT to introduce any at this time. No change made. (7) The SDT has revised the effective date language to reflect the latest guidance received from the Standards Committee. The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.		
MISO		(1) The process described in Attachment 1 may be more suited for inclusion in the Rules of Procedure, similar to the process required for seeking BES facility exceptions. We urge the SDT to consider moving Attachment 1 into a proposed RoP instead of

Organization	Yes or No	Question 5 Comment
		stipulating it in the standard. (2) It may be more appropriate to develop a Standards process that covers the technical aspects of using a footnote 12 and leave regulatory review and approval to FERC and State agencies.

Response:

(1) The SDT respectfully disagrees with the commenter. Inclusion of the Attachment 1 text within the Rules of Procedure might be appropriate for consideration if the process had wide impact on multiple NERC reliability standards. As such, since limited to use within the TPL standards, its inclusion directly within the TPL standard(s) is applicable. No changes made.

(2) The SDT believes the Attachment 1 process strikes the appropriate balance of regulatory oversight. BES Reliability is assured by the Regional Entity and ERO where warranted by assessing any Adverse Reliability Impact. The regulatory authority or governing body responsible for retail electric service issues addresses continuity of service to end-use Load. No change made.

Organization	Yes or No	Question 5 Comment
Deseret Generation & Transmission Cooperative Salt River Project Los Angrles Department of Water and Power Tri-State Generation & Transmission Association, Inc. nevada power company dba nvenergy PG&E Company		: The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2.Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV in P1 is of no value. The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a

Organization	Yes or No	Question 5 Comment
		bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 3The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column.
Hydro-Quebec TransEnergie		Footnote 12 is not applied to Categories P4 and P5, which would include a EHV stuck breaker or failure of a non-redundant relay for a Multiple Contingency. The Load loss restriction for the contingencies listed in P4 and P5 is more restrictive than for the loss of a EHV double circuit line. Statistics indicate that the contingencies presented in P4 and P5 are less frequent. HQT requests that Footnote 12 should also be used for P4 and P5 contingencies for EHV. Even though considering Firm Demand interruption in planning might not be common practice, HQT agrees that the proposed Footnote 12 should maintain such a possibility.
Response: The planning events for which footnote 12 are applicable within the proposed TPL-001-2 standard were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011). The proposed changes are outside of the scope of this project, which aims to clarify the stakeholder approval process. No change made.		
Essential Power, LLC		As written, this change is complex and will be difficult to execute without additional turmoil on the planning end and offers limited clarification. Some additional issues to consider;1. Should this level of contingency allow isolation/removal of load or generation if not part of the outage? 2. Should additional generation be allowed to be removed, again considering the contingency level?
Response: 1. The binary question of applicable use was well vetted during the development of both the revised footnote 'b' and footnote 12. It is clear that some use, appropriately bounded, is the desire of industry and FERC. The SDT believes the proposed Attachment 1 provides the clarity sought by FERC in its remand of footnote 'b' and that the process is reasonable in its approach. No		

Organization	Yes or No	Question 5 Comment
changes made. 2. Generation is not addressed in footnote 'b'. No change made.		
Public Utility District No. 1 of Snohomish County		Comments: SNPD generally disagrees with the draft process that has been developed, and notes that infrequent interruption of small amounts of non-consequential load under limited conditions that does not negatively impact a neighboring TOP is not a reliability issue. Instead it is a cost of service and customer service matter best left to the local and state regulatory bodies. The time and resources spent on this issue at the national level diverts scarse resources and attention from more important efforts that might actually benefit the reliability of the BES. SNPD supports the Pacificorp Revision of TPL-002 footnote 'b' and TPL-001 footnote 1 Comments- The proposed revisions will require regulatory approval for interruptions of firm demand under TPL-002 footnote b or TPL-001 footnote 12 if the voltage level of the contingency is greater than 300 kV with certain sub-conditions or if the planned interruption of firm demand under these footnotes is greater than or equal to 25 MW. The 2011 peak winter and summer loads in the Western Electricity Coordinating Council (WECC) region were 131,471 and 152,211 MW respectively. Total installed generation is 229,189 MW. There are 120,385 miles of AC transmission lines 100 kV and above, and of that total, 31,138 miles of AC transmission lines are operated at voltages above 300 kV. There are 1,744 miles of DC transmission lines.The proposed revisions would add considerable process and documentation for any interruptions, and will require regulatory approval if the interruption is greater than 25 MW. This is 0.016 percent of the WECC peak load. The planning standards already require Category B1 contingencies to be considered which result in the loss of a single generator since individual generator units range in size up to more than 1000 MW. Since these contingencies are routinely studied, it is very, very difficult to imagine that the loss of 25 MW or more of firm demand under TPL-002 footnote b or TPL-001 footnote 12 is so critical to the reliability of the BES that it deserves not only a lengthy footnote, but a two page attachment detailing a

Organization	Yes or No	Question 5 Comment
		complex and lengthy process detailing requirements public meetings, procedures for questions, specifications for documentation, and even a dispute resolution process. As this is not a BES reliability issue, any action regarding potential curtailments of local loads should occur at the local level where the cost and benefit of improvements can be properly assessed. The recent blackout that left 2.7 million customers in Southern California, Arizona and Baja California without power was not due to planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. SNPD is not aware of any regional disturbances or cascading events that were due to planned or controlled interruptions of electric supply where a single contingency occurred on a transmission system. As these proposed requirements could be removed from the Reliability Standards with little or no effect on reliability and would, if anything, increase the efficiency of the ERO compliance program, the proposed limitations on curtailment of firm demand under TPL-002 footnote b or TPL-001 footnote 12 should be removed.
Response: The feedback offered is largely aimed at FERC's jurisdictional issues in regard to continuity of service of end-use Load. FERC Order 762, beginning at Paragraph 23, discusses the FERC's position on jurisdictional issues that are raised by the commenter. This topic was well-vetted in the development of TPL-001-2 and FERC's subsequent NOPR and is beyond the scope/authority of this drafting team. No changes made. In regard to support offered for the Pacificorp proposal, we direct the commenter to view the SDT response to Pacificorp comments.		
Tacoma Power		FERC order 762 states that "to plan for the loss of firm service at the fringes of various systems would be an acceptable approach." The newly defined contingency P2.1 requiring analysis of open ended line sections should allow load shedding of the load on the line section as suggested in the FERC order.
Response: As P2.1 already includes footnote 12, the SDT is assuming that you are supporting the SDT position and thanks you for your support.		

Organization	Yes or No	Question 5 Comment
San Diego Gas & Electric		In FERC Order 762, FERC rejected NERC's footnote (b) and urged "...NERC to develop modifications responsive to the Commission's directives in Order No. 693 and our concerns set forth in this final rule." The NERC SDT has done little to address FERC's concerns and instead has resubmitted the same document with additional language. Order 693 directed NERC to develop modifications to TPL-002-0, which clarify footnote (b). As redrafted, footnote (b) does not address FERC's concerns. For example, footnote (b) continues to use the term "Firm Demand," which describes all forms of demand whether served by the faulted element or not. On the contrary, "consequential load loss" is load, which is removed as a result of a fault. Clearly, these are different concepts and the new language does not comply with FERC's directive. FERC's position has been that non-consequential load loss through load shedding shall not be allowed as an exception to TPL-002-0. Also, FERC has stated that the interruption of Firm Transmission not be allowed as an exception. But, Footnote (b) continues to say, "Curtailment of firm transfers is allowed ...". Another inconsistency. Beyond the differences between what FERC directed NERC to do and what NERC did, as written, footnote (b) would introduce "stakeholder interests" into tranmission reliability even if those interests do not promote reliability. The TPL standards identify the Planning Authority and Transmission Planner as the entities responsible for meeting the standards and makes no mention stakeholders. To meet the reliability objectives of the standard, the Planning Authority and Transmission Planner are subject to Measures and the Compliance Monitoring Process. In FERC Order 762, FERC determined "...that openness and transparency do not alone ensure bulk electric system performance criteria will be met..." and was "...not persuaded that developing technical criteria is unachievable." Although FERC does not disagree with adding a stakeholder process, clearly, they do not endorse one and prefer a technical approach to creating the exception under footnote "b".

Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single

Organization	Yes or No	Question 5 Comment
Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.		
Consolidate Edison Co. of NY, Inc.		Planned interruptions of Firm Demand in response to a Single Contingency (as directed in Footnote b of TPL-002 Table 1, is not an acceptable corrective action to mitigate reliability issues on the BES system. The Interconnected System should be designed and operated with enough transfer capacity to be able to withstand, at a minimum, a single contingency event without service interruptions to customer load. Systems must be designed and operated so that the impact of any single contingency can be mitigated by re-dispatching available system resources without the need to implement load shedding.
Response: The binary question of applicable use was well-vetted during the development of both the revised footnote 'b' and footnote 12. It is clear that some use, appropriately bounded, is the desire of industry and FERC. The SDT believes the proposed Attachment 1 provide the clarity sought by FERC in its remand of footnote 'b' and that the process is reasonable in its approach. No changes made.		
Manitoba Hydro		Please clarify if an entity must set up a stakeholder process if Firm demand interruption is not used as an element of the Corrective Action Plan. As I understand it, the footnote b in TPL 002 will be replicated in the other relevant TPL standards once it is approved. When it is included in the other TPL standards, will it be customized to each standard, or will it appear exactly the same in each standard? Footnote 12 of TPL-001 as currently drafted seems a bit disjointed or incomplete - i.e. its referring to Non Consequential Load Loss and then it refers you to an Attachment for the calculation of Firm Demand interruption without providing a connection

Organization	Yes or No	Question 5 Comment
		between the two concepts .
Response: A process would only be required if an entity allows or intends to utilize planned Load shed to meet the performance requirements for single Contingency (N-1) events. The commenter is correct that the final footnote 'b' and Attachment 1 will be replicated in the other currently-enforceable TPL standards – TPL-001, TPL-002, TPL-003 and TPL-004. The SDT acknowledges that the references to Firm Demand Interruption should reference Non-Consequential Load Loss. The SDT has made revisions to the TPL-001-2a Footnote 12 and Attachment I to show these changes.		
TVA Transmission Reliability Engineering & Controls		Please see answer to question #1. TVA beleives that only load drops of higher magnitudes go thru the Stakeholder and regulatory review.
Response: Please see response to Q1.		
BrightSource Energy, Inc. Utility System Efficiencies, Inc.		The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2.Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV inconsistent with P1.The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore

Organization	Yes or No	Question 5 Comment
		the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 2The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column. The new definition of Non-consequential Load Loss compared to the last version seems to have deleted the reference to Loads that may be lost during transient conditions due to under-frequency load shedding (UFLS), while the reference to Load Loss due to under-voltage load shedding (UVLS) is retained. As a result Load Loss due to UFLS would be part of Non-consequential Load Loss, and will not be allowed under single contingency. Because UFLS may also be triggered during transient simulations, please change the definition for Non-consequential Load Loss to read:"Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load or frequency sensitive Load, or (3) Load that is disconnected from the System by end-user equipment."It is also understood that load loss due to UVLS or UFLS or load that are disconnected from the system by customer equipment are not to be used in meeting steady state reliability requirements. Therefore, in Table 1, please change header-note "i" to read:"The response of voltage sensitive Load and Frequency sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements."

Response: 1 & 2. The SDT disagrees that the use of Footnote 'b' between P1 and P2 for EHV is inconsistent. The SDT believes that the system should be planned so that a fault on an EHV bus section or an internal fault on a non-bus-tie EHV breaker should not require planned Load loss to resolve system performance issues. The planning events for which footnote 12 is applicable within the proposed TPL-001-2 standard were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011). The proposed changes are outside of the scope of this project, which aims to clarify the stakeholder approval process. No change made.

3. The definitions have not been revised, since the standard was approved by the NERC Board of Trustees and changes to those definitions are not in the scope of this project. No change made.

Organization	Yes or No	Question 5 Comment
California Independent System Operator		The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2.Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV in P1 is of no value.The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 3The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column. The process described in Attachment 1 may be more suited for inclusion in the Rules of Procedure, similar to the process required for seeking BES facility exceptions. We urge the SDT to consider moving Attachment 1 into a proposed RoP instead of stipulating it in the standard.
Response: 1 & 2. The SDT disagrees that the use of footnote ‘b’ between P1 and P2 for EHV is inconsistent. The SDT believes that the system should be planned so that a fault on an EHV bus section or an internal fault on a non-bus-tie EHV breaker should not require		

Organization	Yes or No	Question 5 Comment
planned Load loss to resolve system performance issues. The planning events for which footnote 12 is applicable within the proposed TPL-001-2 standard were already vetted by industry and the NERC Board of Trustees (approved on 8/4/2011). The proposed changes are outside of the scope of this project, which aims to clarify the stakeholder approval process. No change made. 3. The SDT disagrees that the attachment should be moved to the NERC Rules of Procedures. Inclusion of the Attachment 1 text within the Rules of Procedure might be appropriate for consideration if the process had wide impact on multiple NERC reliability standards. As such, since limited to use within the TPL standards, its inclusion directly within the TPL standard(s) is applicable. No changes made.		
Georgia Transmission Corporation		The current draft for Requirement 5 (R5) of the NERC Standard TPL-001-3 Draft 1 reads as follows:"Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level."GTC has the following comments regarding TPL-001-3, R5:If the responsible entity has criteria for transient voltage response, along with criteria for acceptable system steady state voltage (including a pre-contingency high and low voltage limit, and a post-contingency high and low voltage limit), then having a steady state post-contingency voltage deviation criteria does not affect the reliability of the bulk electric system (BES). If the system response to a disturbance were to violate either the transient response criteria, or the steady state maximum/minimum voltage criteria, there is potential for loss of integrity of the BES. There is little to no potential for a loss of system integrity due soley to a violation of the steady state voltage deviation criteria. Therefore, Georgia Transmission Corporation requests that R5 not include a requirement to have criteria for post-Contingency voltage deviations.
Response: Requirement R5 requires the Transmission Planner and the Planning Coordinator to have established voltage criteria for their system. This set of criteria is necessary to ensure that the planners are evaluating the voltage excursions (transient and steady state) against their performance criteria. The standard requirements have not been revised since the standard was approved by the NERC Board of Trustees, and changes to those requirements are not in the scope of this project. No change made.		

Organization	Yes or No	Question 5 Comment
Salt River Project		The new definition of Non-consequential Load Loss compared to the last version seems to have deleted the reference to Loads that may be lost during transient conditions due to under-frequency load shedding (UFLS), while the reference to Load Loss due to under-voltage load shedding (UVLS) is retained. As a result Load Loss due to UFLS would be part of Non-consequential Load Loss, and will not be allowed under single contingency. Because UFLS may also be triggered during transient simulations, please change the definition for Non-consequential Load Loss to read:"Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load or frequency sensitive Load, or (3) Load that is disconnected from the System by end-user equipment."It is also understood that load loss due to UVLS or UFLS or load that are disconnected from the system by customer equipment are not to be used in meeting steady state reliability requirements. Therefore, in Table 1, please change header-note "i" to read:"The response of voltage sensitive Load and Frequency sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements."
Response: The definitions have not been revised since the standard was approved by the NERC Board of Trustees, and changes to those definitions are not in the scope of this project. No change made.		
MRO NSRF		The NSRF has concerns that over regulation of footnote "b" or "12" could cause lost opportunities for legitimate growth. An example condition would be the development of a large load in a relatively weak transmission area. Many times new large loads need open undeveloped areas to locate. Without the footnote "b" or "12" option, could an entity be forced to turn away legitimate load growth? The key being that an entity could serve the new large load under normal conditions with easy quick upgrades, but would need 5 - 7 years to construct additional transmission to meet N-1 conditions? Therefore the entity would need to turn away new growth because of over regulation on footnote "b" or "12".

Organization	Yes or No	Question 5 Comment
Response: The SDT does not believe that the proposed revision to footnote 'b' (or footnote 12) will restrict an entity's ability to serve new Load. The SDT has attempted to find a balance between being overly prescriptive and allowing entities the tools they need for planning purposes while responding to the remand from FERC. No change made.		
LCRA Transmission Services Corporation		The primary objection to Footnote 12 is twofold:1. Application to the P3 contingency. This contingency is a Category C contingency under the current NERC TPL-003 standard and allows for load shedding. Thus, the proposed standard revision is a significant and substantial increase in the reliability standard. 2. Use of the term "Firm Demand" as opposed to "Non-Consequential Load Loss." The NERC Glossary defines Firm Demand as "That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions" and Demand as "The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time." Thus interruption of Firm Demand may not result in Non-Consequential Load Loss. Therm "Firm Demand" should be replaces with "Non-Consequential Load Loss."
Response: 1. Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. 2. The SDT determined that it was appropriate to maintain the existing headers in the existing TPL standards and begin using "Non-		

Organization	Yes or No	Question 5 Comment
Consequential Load Loss" with the new TPL-001-2. No change made.		
Electric Reliability Council of Texas, Inc.		The SDT is not required to utilize the stakeholder approach by Order 762 or any other relevant FERC orders. FERC merely provided guidance as to how the rejected proposal could be improved. However, if the SDT elects to pursue an exception process, such exceptions should be based on objective criteria, and the process should be external to the NERC Reliability Standards (e.g. in the Rules of Procedure). In Order 693, FERC directed NERC to clarify footnote (b) to prohibit shedding firm load except for consequential load loss (Order 693 at PP 1773, 1794 and 1797). In a related compliance order, FERC reaffirmed its position. (130 FERC Â¶ 61,200 (March 18, 2010) at PP 8-10 (Compliance Order)) In a subsequent order, FERC clarified that its Order 693 directive did not preclude consideration of specific comments related to planning the system based on load shedding at the "fringes" of a system. (131 FERC Â¶ 61,231 (June 11, 2010) at P 21 (Clarification Order)) FERC held that regional variances for case-specific circumstances or a case-specific exception process to plan for the loss of firm service "at the fringes of various systems" would be acceptable. (131 FERC Â¶ 61,231 (June 11, 2010) at P 21 (Clarification Order)) However, FERC also stated that it viewed the basis for such exceptions as economic, not reliability, with the justification being that it was not economic to invest in the bulk electric system to serve all non-consequential load customers under some single contingency conditions. (Order 693 at P 1792) FERC made clear that any such regional differences or case specific exception processes cannot reflect the lowest common denominator, and, they must be technically justified, and such justification must be strong. (Clarification Order at P 21. See also Order 693 at P 1794) This is consistent with FERC's position that this is a matter of "fundamental issue of transmission service". (Order 693 at P 1793) In recognizing that meeting firm demand under single contingency conditions is fundamental to transmission service, FERC noted that NERC's definition of firm transmission service is the "highest quality (priority) service offered to customers...that anticipates no planned interruption." (Order 693 at P 1793)Against this background, NERC filed revisions to footnote b that allowed transmission plans to shed non-consequential load under single contingency

Organization	Yes or No	Question 5 Comment
		conditions, provided appropriate process applied to such planning determinations/outcomes. In Order No. 762, (139 FERC Â¶ 61,060 (April 19, 2012)) FERC rejected the approach proposed by NERC and provided guidance on acceptable approaches to footnote b. However, FERC did not endorse or mandate any particular approach. Rather, it merely urged "NERC to develop in a timely manner an appropriate modification that is responsive to the Commission's directives in Order No. 693 and our concerns set forth in this Final Rule." (Order 762 at P21) FERC stated that in order for any such proposal to have merit, it must be technically justified and must not reflect the lowest common denominator.As discussed, the proposed stakeholder approach is not appropriate for NERC Reliability Standards. The SDT should abandon that approach and consider simple revisions to footnote b that reference a case by case exception process based on objective criteria that is external to the NERC Reliability Standards (e.g. Rules of Procedure). Alterantively, it should develop revisions to the continent-wide standards that clarify that non-consequential load shedding is not generally permitted for single contingency conditions, but, consistent with FERC's orders, exceptions could be established pursuant to regional rules based on the need/appropriateness in a particular region. Consistent with the above discussion, if the SDT elects to pursue revisions that accommodate shedding non-consequential load in transmission planning for single contingency conditions, it should abandon the stakeholder process approach. The establishment of exceptions is better suited for regional rules or pursuant to a process outside of the reliability standards - e.g. via the Rules of Procedure, because such a process is not suited for a continent-wide reliability standard. Regardless of whether the issue is addressed via an external process, or left to regional variances, this issue needs to be addressed in a relatively timely manner because the uncertainty is affecting planning processes.
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission		

Organization	Yes or No	Question 5 Comment
remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made.		
Southern Company		The use of load dropping should be limited to being only an interim solution while a project is being completed and nothing else can be done.
Response: An entity can choose to restrict the use of footnote 'b' to an interim solution but the SDT believes that there are instances where a long term use (permanent or near-permanent) of footnote 'b' may be appropriate. For example, the amount of Load involved versus the probability of occurrence might dictate that a long term use is in the best overall interests of the customers. No change made.		
Arizona Public Service Company		This process is too prescriptive and must be simplified.
Response: Without specific comments, the SDT is unable to respond.		
Ameren		To clarify, the Stakeholder Process should not be initiated until the amount of Firm Demand expected to be interrupted by the TP or PC as mitigation reaches a threshold of 10 MW. However, at that point, the Stakeholder Process should commence, but not without incorporating the need to obtain approvals from the stakeholders, regardless of the amount of load to be interrupted beyond the 10 MW threshold level, and regardless of the voltage level of the transmission elements involved in the contingency event(s). As drafted, the Stakeholder Process appears to be silent on receiving approvals to drop load of less than 25 MW. We believe that this is an invitation to trouble for the industry. For example, if a TP or PC were to have a contingency for which the mitigation is to interrupt 15 MW of Firm Demand, all the stakeholders would be called in just to inform them that their load is subject to

Organization	Yes or No	Question 5 Comment
		interruption, but their displeasure is not relevant, because the 25 MW interruption level had not been reached, and approval is not required. Thus, we believe that as drafted Stakeholder Process needs some additional work before we could support it.
Response: The stakeholder process is required anytime that Load is planned to be interrupted pursuant to footnote 'b'. Approval by the applicable regulatory authority or governing body responsible for retail electric service issues is required for planned interruptions greater than 25 MW. The SDT believes that this level is the appropriate balance to protect the interests of the customers without being unduly burdensome. No change made.		
Southwest Power Pool Reliability Standards Development Team		We agree the distinction between consequential and non- consequential is necessary. We don't agree that you should plan for non-consequential load loss/shed. You shouldn't have to interrupt firm service for n-1 contingency.
Response: The SDT believes that there are instances where use of footnote 'b' may be appropriate. For example, the amount of Load involved versus the probability of occurrence might dictate that a use of footnote 'b' is in the best overall interests of the customers. No change made.		
Nova Scotia Power		With regard to the application of Footnote 12 in TPL-001-3, the footnote is only applied to the contingencies in Table 1 involving loss of a Single Line with a 3 phase fault (P1) or opening of a line without a fault (P2-1). These are higher probability events relative to other types of contingencies, and Footnote 12 allows for loss of load for these events, but does not allow for loss of load for lower probability events that have the same results, such as P2-2 and P2-3. Take for example a single radial 345kV line feeding a small radial portion of the system, with a line end transformer and breaker between the transformer and the line. Application of Footnote 12 to only a P1 event (loss of the line on its own, or loss of the transformer on its own) but loss of the breaker between the line and the transformer would not be allowed, even though the result would be the same. Without applying footnote 12 to category P2-2 and P2-3 would mean that Footnote 12 is rendered moot (can never be used). Similarly, Footnote 12 should be applied to P4 and P5, essentially wherever Footnote 9 is applied, otherwise Footnote 12 can never be applied.

Organization	Yes or No	Question 5 Comment
Response: Industry and the NERC Board of Trustees have approved the use of a Stakeholder Process to address the concerns with the original footnote 'b' and with footnote 12 in TPL-001-2. The Commission's Order No. 762 found that NERC's proposed Transmission Planning Reliability Standard TPL-002-0b, which includes a provision that allows for planned Load shed in a single Contingency provided that the plan is documented and alternatives are considered in an open and transparent process ("footnote b"), is vague, unenforceable, and not responsive to the previous Commission directives on this matter. Accordingly, the Commission remanded NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. FERC remanded the standard; not because it contained a Stakeholder Process, but because they wanted the process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. This draft added detail and specificity to the already-approved approach. Based on these facts, the SDT does not believe it appropriate to move away from the industry and Board of Trustees approved Stakeholder Process approach. No change made. The SDT believes that the system should be planned so that a fault on an EHV bus section (or an internal fault on a non-bus-tie EHV breaker) should not require planned Load loss to resolve system performance issues. No change made.		
Northeast Power Coordinating Council		NPCC reviewed the posted documents, and has no comments for this posting.

END OF REPORT

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR approved by SC in May 2012.
2. Initial comment period July 31, 2012 – August 29, 2012.

Proposed Action Plan and Description of Current Draft:

The SDT is working to address FERC's remand of the proposed clarification of TPL-002, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System. That footnote is captured here as footnote 12.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Initial ballot	October 2012
2. Recirculation ballot	December 2012
3. BOT approval	February 2013

Definitions of Terms Used in Standard

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

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

A. Introduction

1. **Title: Transmission System Planning Performance Requirements**

2. **Number: TPL-001-2a**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

    4.1. Functional Entity

    4.1.1. Planning Coordinator.

    4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

    Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

    For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-2a:

    - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
    - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
    - P2-1
    - P2-2 (above 300 kV)
    - P2-3 (above 300 kV)
    - P3-1 through P3-5
    - P4-1 through P4-5 (above 300 kV)
    - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.

- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past

studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the

use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

<table>
<tr><th colspan="2">Table 1 – Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">Steady State & Stability
For all extreme events evaluated:
a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
b. Simulate Normal Clearing unless otherwise specified.</td></tr>
<tr><td>Steady State
1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
a. Loss of a tower line with three or more circuits.[11]
b. Loss of all Transmission lines on a common Right-of-Way[11].
c. Loss of a switching station or substation (loss of one voltage level plus transformers).
d. Loss of all generating units at a generating station.
e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
a. Loss of two generating stations resulting from conditions such as:
i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
ii. Loss of the use of a large body of water as the cooling source for generation.
iii. Wildfires.
iv. Severe weather, e.g., hurricanes, tornadoes, etc.
v. A successful cyber attack.
vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
b. Other events based upon operating experience that may result in wide area disturbances.</td>
<td>Stability
1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
e. 3Ø internal breaker fault.
f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances</td></tr>
</table>

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled ‘Initial Condition’) and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner’s planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed ‘75’ MW.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

  b. Assessment of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to mitigate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW.

Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	03/17/2001	Revision of TPL-001-0 to modify only Table 1 footnote b. Approved by Board of Trustees	Project 2006-02 – revision to address FERC directive
2	To be Determined	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2a	February 2013	Address remand of proposed footnote 'b' pursuant to FERC Order RM06-16-009	Revised

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR approved by SC in May 2012.
2. Initial comment period July 31, 2012 – August 29, 2012.

Proposed Action Plan and Description of Current Draft:

The SDT is working to address FERC's remand of the proposed clarification of TPL-002, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System. That footnote is captured here as footnote 12.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Initial ~~posting~~ballot	~~July~~October 2012
2. Recirculation ballot	~~October~~December 2012
3. BOT approval	February 2013

Definitions of Terms Used in Standard

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

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-2a**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where ~~no~~ regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where ~~no~~ regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where ~~no~~ regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-2a:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.

- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past

studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the

use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
      ii. Loss of the use of a large body of water as the cooling source for generation.
      iii. Wildfires.
      iv. Severe weather, e.g., hurricanes, tornadoes, etc.
      v. A successful cyber attack.
      vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
   b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   e. 3Ø internal breaker fault.
   f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process ~~should be~~is to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. ~~However, i~~In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, ~~W~~when Non-Consequential Load Loss is utilized within the Near-Term Transmission ~~p~~Planning ~~process~~Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss ~~is~~ meets the conditions shown in Attachment 1. In no case can the planned ~~Firm Demand interruption~~ Non-Consequential Load Loss under footnote 12 exceed '~~x~~75' MW.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of ~~Firm Demand interruption~~ Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .~~shall document the stakeholder process which shall~~ The process must include the following:

1. Meetings must be open to ~~all~~ affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to ~~all~~ affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific ~~applications~~location(s) of the planned ~~Firm Demand interruption~~ Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed ~~Firm Demand interruption~~ Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of ~~Firm Demand interruption~~ Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which ~~Firm Demand interruption~~ Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of ~~Firm Demand~~ Non-Consequential Load Loss ~~MW to be interrupted~~ with:

   a. The estimated number and type of customers affected
   b. ~~An a~~Assessment of the effect of the use of ~~Firm Demand interruption~~ Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of ~~Firm Demand interruption~~ Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of ~~Firm Demand interruption~~ Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to mitigate the need for ~~Firm Demand interruption~~ Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to ~~Firm Demand interruption~~ Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission ~~p~~Planners and Planning Coordinators

III. Instances for which Regulatory Review ~~Approval~~ of ~~Interruptions of Firm Demand~~ Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ~~Approval~~ assure that ~~of the use of Firm Demand interruption under footnote 12 by~~ the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Non-Consequential Load Loss under footnote 12 ~~is required~~ if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for ~~Firm Demand interruptions~~ Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned ~~Firm Demand interruption~~ Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

~~Before a Firm Demand interruption under footnote 12 is allowed to be utilized as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that approval is obtained from the regulatory authority or governing body responsible for retail electric service issues.~~

In no case can the planned ~~Firm Demand interruption~~ Non-Consequential Load Loss under footnote 12 exceed ~~x~~75 MW.

Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Non-Consequential Load Loss under footnote 12 ~~When approval for the use of a footnote 12 Firm Demand interruption is necessary under items III.1 or III.2 above,~~ the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ~~Regional Entity~~ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss. ~~Within 45 days of receipt of this information, the Regional Entity must review each proposed use of Firm Demand interruption under footnote 12 to verify that there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity's footprint. If the Regional Entity states that an Adverse Reliability Impact will result due to the requested Firm Demand interruption, then the requesting entity may appeal the decision to the ERO. Regional Entity determinations of Adverse Reliability Impacts are to be evaluated by the Regional Entity through a published methodology approved by the ERO.~~

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	03/17/2001	Revision of TPL-001-0 to modify only Table 1 footnote b. Approved by Board of Trustees	Project 2006-02 – revision to address FERC directive
2	To be Determined	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2a	February 2013	Address remand of proposed footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Implementation Plan for TPL-001-2a

Prerequisite Approvals

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

TPL-001-2a — Transmission System Planning Performance Requirements

Revision to Sections of Approved Standards and Definitions

There are multiple new definitions in the proposed standard.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Compliance with Standards

Standard	Functions That Must Comply With the Associated Requirements	
	Transmission Planner	Planning Coordinator
TPL-001-2 — Transmission System Planning Performance Requirements	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after

Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2a, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-2a:

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

TPL-001-1, TPL-002-1c, TPL-003-1a, and TPL-004-1 are being retired as they are replaced in their entirety by TPL-001-2a. TPL-005-0 and TPL-006-0.1 are being retired because their requirements are adequately covered by the revised TPL-001-2a and NERC's Rules of Procedure, Section 800. TPL-001-1, TPL-002-1c, TPL-003-1a, TPL-004-1, TPL-005-0 and TPL-006-0.1 are being retired on midnight of the day immediately prior to the Effective Date of TPL-001-2a in the particular jurisdictions in which TPL-001-2a is becoming effective. However, during this 24-month period, all aspects of TPL-001-1 through TPL-006-0.1 shall remain in effect for compliance monitoring. This 24 month period is to allow entities to develop, perform and/or validate new and/or modified studies, methodologies, assessments, procedures, etc. necessary to implement and meet the TPL-001-2a requirements. The specified effective dates are expected to allow sufficient time for proper assessment of the available options necessary to create a viable Corrective Action Plan that is compliant with the new Standard.

R1. This Requirement is related to maintaining System models and the data needed to do so. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

R7. This Requirement identifies an obligation to determine individual and joint responsibilities for performing studies needed to do the Planning Assessment. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

TPL-001-2a 'raises the bar' in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-1, TPL-002-1c, TPL-003-1a and TPL-004-1 because loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by many to allow such actions. As shown in Table 1 of TPL-001-2a, the performance requirements associated with the following events represent "raising the bar":

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

This "raising the bar" is beyond the control of the Transmission Planner and Planning Coordinator and may have significant budget, siting, permitting, and construction impacts on many Transmission Owners. To provide stakeholders with sufficient time to implement changes, a timeframe coincident with the end of the Near-Term Transmission Planning Horizon has been provided.

Any entity which cannot eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for these performance elements by that date shall submit a mitigation plan to its Regional Entity outlining the steps it will take to correct the problem. If the entities follow the established ERO procedure for mitigation, it is the intent of the SDT that no penalties will be assessed.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR approved by SC in May 2012.
2. Initial comment period July 31, 2012 – August 29, 2012.

Proposed Action Plan and Description of Current Draft:

The SDT is working to address FERC's remand of the proposed clarification of TPL-002, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System. Table 1 appears in the first four of the current TPL standards but footnote 'b' only applies to TPL-002. Therefore, only TPL-002 is being posted for industry comment at this time. When the footnote has been approved, all four of the applicable TPL standards will be filed with the Commission.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Initial ballot	October 2012
2. Recirculation ballot	December 2012
3. BOT approval	February 2013

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-1c

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised
1c	February 2013	Address remand of proposed footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote ‘b’ is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Firm Demand interruption under footnote ‘b’
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote ‘b’ (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote ‘b’ utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote ‘b’ which must include the following:

1. Conditions under which Firm Demand interruption under footnote ‘b’ would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Firm Demand MW to be interrupted with:
    a. The estimated number and type of customers affected

  b. Assessment of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community
3. Estimated frequency of Firm Demand interruption under footnote ‘b’ based on historical performance
4. Expected duration of Firm Demand interruption under footnote ‘b’ based on historical performance
5. Future plans to mitigate the need for Firm Demand interruption under footnote ‘b’
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote ‘b’
8. Assessment of potential overlapping uses of footnote ‘b’ including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Interruptions of Firm Demand under Footnote ‘b’ is Required

Before a Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote ‘b’ if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote ‘b’, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote ‘b’ is greater than or equal to 25 MW

In no case can the planned Firm Demand interruption under footnote ‘b’ exceed 75 MW.

Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote ‘b’, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR approved by SC in May 2012.

~~1.~~2. Initial comment period July 31, 2012 – August 29, 2012.

Proposed Action Plan and Description of Current Draft:

The SDT is working to address FERC's remand of the proposed clarification of TPL-002, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System. Table 1 appears in the first four of the current TPL standards but footnote 'b' only applies to TPL-002. Therefore, only TPL-002 is being posted for industry comment at this time. When the footnote has been approved, all four of the applicable TPL standards will be filed with the Commission.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Initial ~~posting~~ ballot	~~July~~October 2012
2. Recirculation ballot	~~October~~December 2012
3. BOT approval	February 2013

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-1c

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory ~~approval~~authorities. In those jurisdictions where ~~no~~ regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised
1c	February 2013	Address remand of proposed footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	 No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process ~~should be~~is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. ~~Furthermore, i~~In limited circumstances, Firm Demand may ~~need to~~ be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, ~~W~~when interruption of Firm Demand is utilized within the Near-Term Transmission ~~p~~Planning ~~process~~ Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed '~~x~~75' MW.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 'b' is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. ~~shall document the stakeholder process which shall~~ The process must include the following:

1. Meetings must be open to ~~all~~ affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to ~~all~~ affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific ~~applications~~ location(s) of the planned Firm Demand interruption under footnote 'b'
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote 'b' (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote 'b' which must include the following:

1. Conditions under which Firm Demand interruption under footnote 'b' would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency

2. Amount of Firm Demand MW to be interrupted with:
   a. The estimated number and type of customers affected
   b. ~~An a~~Assessment of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community
3. Estimated frequency of Firm Demand interruption under footnote ‘b’ based on historical performance
4. Expected duration of Firm Demand interruption under footnote ‘b’ based on historical performance
5. Future plans to mitigate the need for Firm Demand interruption under footnote ‘b’
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote ‘b’
8. Assessment of potential overlapping uses of footnote ‘b’ including overlaps with adjacent Transmission ~~p~~Planners and Planning Coordinators

III. Instances for which Regulatory Review ~~Approval~~ of Interruptions of Firm Demand under Footnote ‘b’ is Required

Before a Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ~~Approval~~assure that ~~of the use of Firm Demand interruption under footnote ‘b’ by~~ the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote ‘b’ ~~is required~~ if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote ‘b’, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote ‘b’ is greater than or equal to 25 MW

~~Before a Firm Demand interruption under footnote ‘b’ is allowed to be utilized as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that approval is obtained from the regulatory authority or governing body responsible for retail electric service issues.~~

In no case can the planned Firm Demand interruption under footnote ‘b’ exceed ~~x~~75 MW.

Once assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote ‘b’~~When approval for the use of a footnote ‘b’ Firm Demand interruption is necessary under items III.1 or III.2 above~~, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ~~Regional Entity~~ ~~Entity~~ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption. ~~Within 45 days of receipt of this information, the Regional Entity must review each proposed use of Firm Demand interruption under footnote ‘b’ to verify that there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity’s footprint. If the Regional Entity states that an Adverse Reliability Impact will result due to the requested Firm Demand interruption, then the requesting entity may appeal the decision to the ERO. Regional Entity determinations of Adverse Reliability Impacts are to be evaluated by the Regional Entity through a published methodology approved by the ERO.~~

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

Implementation Plan for Project 2010-11: TPL Table 1 Order

Standards Involved:

- TPL-001-1 — System Performance Under Normal (No Contingency) Conditions (Category A)
- TPL-002-1c — System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- TPL-003-1 — System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
- TPL-004-1 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

Prerequisite Approvals

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

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed standards and no proposed changes to other standards.

Compliance with Standards

The four standards are all applicable to both the Transmission Planner and the Planning Authority.

Effective Dates

The effective date is the date entities are expected to meet the performance identified in these standards.

The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective.

All other requirements remain in effect per previous approvals.

Project Revision of TPL-002 footnote ‘b’ and TPL-001 footnote 12

Unofficial Comment Form

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by **8 p.m. November 19, 2012**. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

You can access the project webpage here.

Background Information

This posting is soliciting formal comment.

FERC Order No. 762 issued April 19, 2012 remanded TPL-002-1b as vague, unenforceable, and not responsive to the previous Commission directives on this matter. The Standards Committee directed the Standards Drafting Team (SDT) to revise footnote ‘b’ in accordance with the directives of Orders No. 693 and 762. The SDT was also charged with revising the corresponding footnote 12 of TPL-001-2 in order to prevent the remand of TPL-001-2.

The SDT adopted a philosophy of minimal changes to the actual footnote itself. This was done to minimize confusion as to what was changed, for ease of reading and following the footnote, and for formatting within the actual standards documents. This philosophy resulted in the development of an attachment to the footnote where the actual changes in response to the Commission Orders are contained. It should be noted that attachments to standards are part and parcel of the standard itself and thus are binding to applicable entities.

A data request to collect data to assist the SDT in its work was posted for response in accordance with Section 1600 of the NERC Rules of Procedure. A spreadsheet summarizing the data request findings has been included with this posting. Specifically, the data obtained led to the following decisions:

- Order 762 provided guidance suggesting that a ceiling for footnote ‘b’ use be established. Therefore, the SDT has set the ceiling for footnote ‘b’ use at 75 MW based on the data provided. Currently, five entities reported that they utilized footnote ‘b’ for single Contingencies in their planning process for between 50 and 75 MW of potential Load shed and no entity reported that it utilized footnote ‘b’ for more than 75 MW. The SDT believes that with the Stakeholder Process, the involvement of local regulatory and governmental bodies and by setting a ceiling value for the first time, that it has significantly raised the bar on this issue. Furthermore, the SDT does not believe that it is appropriate to set a limit that would automatically eliminate some existing usages and force those entities to construct new transmission facilities.

- As shown in the data request findings, the average number of MW used with footnote 'b' is approximately 19 MW. The SDT has set the threshold value for when regulatory review is required at 25 MW based on this average value. The SDT believes that setting this value as indicated by the data request findings sets the appropriate balance between the stakeholder process and the additional step of obtaining regulatory and ERO reviews. And again, the SDT believes that setting this threshold value so that regulatory and ERO reviews are required for instances of footnote 'b' utilization between 25 and 75 MW significantly raises the bar.
- The data request showed that the majority of footnote 'b' utilizations were at voltage levels below 300 kV. The SDT believes that this validates the selection of the 300 kV EHV distinction in Section III of the Attachment where regulatory and ERO reviews are required.
- The majority of Contingencies cited as causing an entity to utilize footnote 'b' were line outages. This caused the SDT to consider limiting the use of footnote 'b' to such types of Contingencies and eliminating its usage for transformer outages. However, with the number of instances of transformer outages reported (11), the SDT did not believe such a step was warranted and has not set up a constraint as to types of Contingencies in association with footnote 'b' utilization.
- The data obtained did not indicate any way to isolate usage of footnote 'b' to the fringes of the system whether that meant geographical or electrical fringes. The SDT believes that constraining the use of footnote 'b' to the supposed fringes of a system could potentially be discriminatory and thus invalid. In addition, the introduction of the Stakeholder Process for all uses of footnote 'b' and the regulatory and ERO reviews for the 25 – 75 MW range of use will allow for a true indication of whether the use of footnote 'b' is infringing on societal values which should be a better arbiter of what constitutes a fringe of the system.

The SDT has made a number of changes to the Attachment based on comments received from the first posting. Principal among these, was the deletion of the role of the Regional Entity in the review process and the clarification of the role of the regulatory authorities from approval to review.

The SDT reminds commenters that the Stakeholder Process was previously approved by the NERC Board of Trustees and that inclusion of this process is not the issue. The issue is clarifying the details of that process to answer the concerns in Order 762.

There have been no changes to the Implementation Plan originally filed with the standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format. Bullets, numbers, and special formatting will not be retained.

Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.

Questions

1. Do you agree with the text in the body of the footnote including the maximum capacity threshold? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. For the maximum capacity item, please supply any technical rationale for your comment along with limiting conditions and any current criteria in use at your entity.

☐ Yes

☐ No

Comments:

2. Do you agree with the description and components of the the Stakeholder Process in Section I of Attachment 1? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes

☐ No

Comments:

3. Do you agree with the Information for Inclusion in the Stakeholder Process contained in Section II of Attachment1? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes

☐ No

Comments:

4. Do you agree with the text in Section III of Attachment 1? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes

☐ No

Comments:

5. If you have any other comments on this Standard that you haven't already mentioned above, please provide them here:

Comments:

Number	Max MW	Number of instances	Voltage	MW each instance	Planned upgrade	Estimated cost ($M)	Expected In-Service Date	Type of Contingency
1	43	4	230	8.4	No			line
1			230	8.4	No			transformer
1			230	43	No			line
1			115	14	No			line
2	69	1	230	69	No			line
3	12	1	100	12	Yes	38.6	2017	line
4	4.3	3	161	2.5	Yes	3 - 12	2015	line
4			161	4.1	Yes	3 - 12	2014	line
4			161	4.3	Yes	3 - 12	2021	line
5	40	4	138	10	Yes			line
5			138	25	Yes			line
5			230	40	Yes			line
5			138	10	Yes	0.2	2011	line
6	30	1	115	30	Yes	5.8	2013	line
7	31	1	115	31	Yes	9.5	2013	line
8	50	7	115	10	No			line
8			115	12	Yes		2012	line
8			115	9	Yes			line
8			115	15	Yes		2013	line
8			115	50	No			line
8			115	31.8	No			line
8			115	17.1	No			line
9	20	2	115	20	Yes	4.7	2014	unspecifed
9			115	20	Yes	4.7	2014	unspecifed
10	40	3	115	40	Yes	33	2012	line
10			230	40	Yes	8 - 15	2013	transformer
10			115	20	No	10 - 20	None	line
11	39	1	115	39	Yes	100	2012	line
12	63	24	115	40	No			line
12			138	40	No			line
12			138	3	No			line
12			138	20	No			line
12			138	15	No			line

12			138	63	No			line
12			115	40	No			line
12			138	40	No			line
12			138	3	No			line
12			115	62	No			line
12			138	40	No			line & transformer
12			138	61	No			line & transformer
12			115	4	Yes	17.4	2013	line
12			115	7	Yes	15.7	2014	line
12			115	7	Yes		2014	transformer
12			115	6	Yes	46	2012	transformer
12			115	6	Yes		2012	line
12			115	11	Yes		2014	line
12			115	11	Yes		2014	transformer
12			115	6	Yes		2012	line & transformer
12			115	6	Yes		2012	line
12			115	20	Yes	13	2010	line
12			115	6	Yes		2012	line & transformer
12			115	2	Yes		2010	line
13	20	2	115	20	No	5.4		transformer
13			115	14	No	5.4		transformer
14	55	1	138	55	No	80		line
15	28	1	161	28	Yes	12.5	2020	line
16	75	19	138	75.2	Yes	15.9	2013	line
16			138	3.7	Yes	4.1	2013	line
16			115	1.2	Yes	1	2013	line
16			138	7.7	Yes	7.5	2013	line
16			115	15.7	Yes	8.8	2014	line
16			115	2.1	Yes	36.4	2014	line
16			230	11.3	Yes	44.4	2015	line
16			115	5.9	Yes	20.3	2015	line
16			115	19.9	Yes	59	2015	line
16			115	19.8	Yes	62.7	2015	line
16			500	3.4	Yes	16.4	2018	line
16			500	17.5	Yes	0.6	TBD	line
16			115	0.3	Yes	14.5	2014	line
16			115	5	Yes	3.8	2013	line

16			115	8.6	Yes	14.5	2013	line
16			115	7.1	Yes	0.1	2012	line
16			115	2.7	Yes	3.76	2012	line
16			115	12.5	Yes	1.3	2011	line
16			500	28.3	Yes	12.9	2013	line
17	8	1	230	8	Yes	8	2014	line
18	9	2	115	4.1	Yes	14.5	2019	line
18			115	9.1	Yes	9.75	2012	line

Total Instances	78

	No	Yes
Utilize 'b'	171	18

139 FERC ¶ 61,060
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM11-18-000; Order No. 762]

Transmission Planning Reliability Standards

(Issued April 19, 2012)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: Under section 215 of the Federal Power Act, the Federal Energy Regulatory Commission remands proposed Transmission Planning (TPL) Reliability Standard TPL-002-0b, submitted by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. The proposed Reliability Standard includes a provision that allows for planned load shed in a single contingency provided that the plan is documented and alternatives are considered and vetted in an open and transparent process. The Commission finds that this provision is vague, unenforceable and not responsive to the previous Commission directives on this matter. Accordingly, the Final Rule remands NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest.

DATES: This rule will become effective **[Insert date 60 days after publication in the FEDERAL REGISTER].**

ADDRESSES: You may submit comments, identified by docket number by any of the following methods:

- Agency Web Site: http://www.ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Commenters unable to file comments electronically must mail or hand deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

139 FERC ¶ 61,060
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

Transmission Planning Reliability Standards Docket No. RM11-18-000

Order No. 762

FINAL RULE

(Issued April 19, 2012)

1. Under section 215(d) of the Federal Power Act,[1] the Commission remands proposed Transmission Planning (TPL) Reliability Standard TPL-002-0b, submitted by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. The proposed Reliability Standard includes a provision that allows for planned load shed in a single contingency provided that the plan is documented and alternatives are considered and vetted in an open and transparent process.[2] The Commission finds that this provision is vague, unenforceable and not responsive to the previous Commission directives on this matter. Accordingly, the Final

[1] 16 U.S.C. § 824o(d)(4) (2006).

[2] NERC filed a petition seeking approval of Table 1, footnote 'b' of four Reliability Standards: Transmission Planning: TPL-001-1– System Performance Under Normal (No Contingency) Conditions (Category A), TPL-002-1b – System Performance Following Loss of a Single Bulk Electric System Element (Category B), TPL-003-1a – System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), and TPL-004-1– System Performance Following Extreme Events Resulting

(continued…)

Rule remands NERC's proposal as unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. We require NERC to utilize its Expedited Reliability Standards Development Process to develop timely modifications to TPL-002-0b, Table 1 footnote 'b' in response to our remand.[3]

I. Background

2. Section 215 of the FPA requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Approved Reliability Standards are enforced by the ERO, subject to Commission oversight, or by the Commission independently. On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including Reliability Standard TPL-002-0.[4] In addition, pursuant to section 215(d)(5) of the FPA,[5] the Commission directed

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in the Loss of Two or More Bulk Electric System Elements (Category D). While footnote 'b' appears in all four of the above referenced TPL Reliability Standards, its relevance and practical applicability is limited to TPL-002-0a.

[3] NERC Rules of Procedure, Appendix 3A, Standard Processes Manual at 34 (effective January 31, 2012).

[4] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[5] 16 U.S.C. § 824o(d)(5)(2006).

NERC to develop modifications to 56 of the 83 approved Reliability Standards, including footnote 'b' of Reliability Standard TPL-002-0.[6]

A. Transmission Planning (TPL) Reliability Standards

3. Currently-effective Reliability Standard TPL-002-0b addresses Bulk-Power System planning and related transmission system performance for single element contingency conditions. Requirement R1 of TPL-002-0b requires that each planning authority and transmission planner "demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the network can be operated to supply projected customer demands and projected firm transmission services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I."[7] Table I identifies different categories of contingencies and allowable system impacts in the planning process. With regard to system impacts, Table I further provides that a Category B (single) contingency must not result in cascading outages, loss of demand or curtailed firm transfers, system instability or exceeded voltage or thermal limits. With regard to loss of demand, current footnote 'b' of Table 1 states:

> Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems.

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[6] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1797.

[7] Reliability Standard TPL-002-0a, Requirement R1.

> To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

B. Order No. 693 Directive

4. In Order No. 693, the Commission stated that it believes that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential firm load in the event of a single contingency.[8] The Commission directed the ERO to develop certain modifications, including a clarification of Table 1, footnote ‘b.’

5. In a subsequent clarifying order, the Commission stated that it believed that a regional difference, or a case-specific exception process that can be technically justified, to plan for the loss of firm service would be acceptable in limited circumstances.[9] Specifically, the Commission stated that “a regional difference, or a case-specific exception process that can be technically justified, to plan for the loss of firm service at the fringes of various systems would be an acceptable approach.”[10]

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[8] *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1794.

[9] *Mandatory Reliability Standards for the Bulk Power System*, 131 FERC ¶ 61,231, at P 21 (2010) (June 2010 Order).

[10] *Id.*

C. NERC Petition

6. On March 31, 2011, NERC filed a petition seeking approval of its proposal to revise and clarify footnote 'b' "in regard to load loss following a single contingency."[11] NERC stated that it did not eliminate the ability of an entity to plan for the loss of non-consequential load in the event of a single contingency but drafted a footnote that, according to NERC, "meets the Commission's directive while simultaneously meeting the needs of industry and respecting jurisdictional bounds."[12] NERC stated that its proposed footnote 'b' establishes the requirements for the limited circumstances when and how an entity can plan to interrupt Firm Demand for Category B contingencies. According to NERC, the provision allows for planned interruption of Firm Demand when "subject to review in an open and transparent stakeholder process."[13] NERC's proposed footnote 'b' states:

> An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate redispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements.

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[11] NERC Petition at 10.

[12] *Id.*

[13] *Id.*

> When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

7. NERC supplemented the filing on June 7, 2011, in response to a Commission deficiency letter. NERC explained that "the approach proposed in footnote 'b' is equally efficient because many of the stakeholder processes that will be used in footnote 'b' planning decisions are already in place, as implemented by FERC in Order No. 890 and in state regulatory jurisdictions."[14] NERC also pointed to state public utility commission processes or processes existing in local jurisdictions that address transmission planning issues that could serve to provide a case-specific review of the planned interruption of Firm Demand. According to NERC, such processes would more likely engage the appropriate local-level decision-makers and policy-makers.

8. With respect to review and oversight by NERC and the Regional Entities, NERC submitted that an ERO-specific process would place the ERO in the position of managing and actively participating in a planning process, which conflicts with its role as the compliance monitor and enforcement authority. NERC also stated that neither the ERO nor the Regional Entities will review decisions regarding planned interruptions. Their role will be limited to reviewing whether the registered entity participated in a stakeholder process when planning to interrupt Firm Demand. NERC explained that

[14] NERC Data Response at 4.

Regional Entities will have oversight after-the-fact by auditing the entity's implementation of footnote 'b' to determine if the entity planned on interrupting Firm Demand and whether the decision by the entity to rely on planned interruption of Firm Demand was vetted through the stakeholder process and qualified as one of the situations identified in footnote 'b.'

9. Furthermore, NERC stated that an objective of the planning process should be to minimize the likelihood and magnitude of planned Firm Demand interruptions. NERC contended that, due to the wide variety of system configurations and regulatory compacts, it is not feasible for the ERO to develop a one-size-fits-all criterion for limiting the planned firm load interruptions for Category B events. According to NERC, the standards drafting team evaluated setting a certain magnitude of planned interruption of Firm Demand, but there was no analytical data to support a single value, and it would be viewed as arbitrary.

D. Notice of Proposed Rulemaking

10. On October 20, 2011, the Commission issued a Notice of Proposed Rulemaking (NOPR[15]) proposing to remand NERC's proposal to modify footnote 'b.' In the NOPR, the Commission stated that it believed that NERC's proposal does not meet the directives in Order No. 693 and the June 2010 Order and does not clarify or define the circumstances in which an entity can plan to interrupt Firm Demand for a single

[15] *Transmission Planning Reliability Standards*, Notice of Proposed Rulemaking, 76 FR 66229 (Oct. 20, 2011), FERC Stats. & Regs. ¶ 32,683 (2011).

contingency. The Commission expressed concern that the procedural and substantive parameters of NERC's proposed stakeholder process are too undefined to provide assurances that the process will be effective in determining when it is appropriate to plan for interrupting Firm Demand, does not contain NERC-defined criteria on circumstances to determine when an exception for planned interruption of Firm Demand is permissible, and could result in inconsistent results in implementation. The NOPR stated that the proposed footnote effectively turns the processes into a reliability standards development process outside of NERC's existing procedures. Furthermore, the NOPR stated that regardless of the process used, the result could lead to inconsistent reliability requirements within and across reliability regions. While the Commission recognized that some variation among regions or entities is reasonable, there are no technical or other criteria to determine whether varied results are arbitrary or based on meaningful distinctions.

11. The Commission proposed to provide further guidance on acceptable approaches to footnote 'b' and sought comment on certain options for revising footnote 'b', as well as other potential options to solve the concerns outlined in the NOPR. In response to the NOPR, comments were filed by seventeen interested parties.[16]

[16] NERC, The Edison Electric Institute (EEI), American Public Power Association (APPA), National Association of Regulatory Utility Commissioners (NARUC), ITC Holdings Corp. (ITC), Manitoba Hydro, California Department of Water Resources State Water Project (California SWP) Hydro One Networks, Inc and the Ontario Independent Electricity System Operator (Hydro One and IESO), Duke Energy Corporation (Duke), New York State Public Service Commission (NYPSC), Bonneville Power Administration

(continued…)

II. Discussion

12. For the reasons discussed below, the Commission concludes that NERC's proposed TPL-002-0b does not meet the Commission's Order No. 693 directives, nor is it an equally effective and efficient alternative. Further, the Commission finds that the proposal is vague, potentially unenforceable and may lack safeguards to produce consistent results. On this basis, the Commission remands the proposal to NERC as unjust, unreasonable, unduly discriminatory or preferential and not in the public interest. Below, the Commission also provides guidance on acceptable approaches to footnote 'b.'

13. The Commission adopts the proposed NOPR finding that the footnote 'b' process lacks adequate parameters. The Reliability Standard requires that, when planning to interrupt Firm Demand, the Firm Demand interruption must be "subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments."[17] Without meaningful substantive parameters governing the stakeholder process, the enforceability of this obligation by NERC and the Regional Entities would be limited to a review to ensure only that a stakeholder process occurred. As NERC explained, Regional Entities' involvement is limited to after-the-fact oversight by

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(BPA), Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company (KCPL), Midwest Independent System Operator, Inc. (MISO), Public Utility District No. 1 of Snohomish County, Washington, (Snohomish), Transmission Access Policy Study Group (TAPS), Powerex Corp. (Powerex), and Florida Reliability Coordinating Council (FRCC).

[17] NERC Petition at 10.

auditing the entity's implementation of footnote 'b' to determine if the entity planned on interrupting Firm Demand and whether the decision by the entity to rely on planned interruption of Firm Demand was vetted through the stakeholder process and qualified as one of the situations identified in footnote 'b.'[18]

14. Further, the NERC proposal leaves undefined the circumstances in which it is allowable to plan for Firm Demand to be interrupted in response to a Category B contingency. The Commission believes that proposed footnote 'b' could be used as a means to override the reliability objective and system performance requirements of the TPL Reliability Standard without any technical or other criteria specified to determine when planning to interrupt Firm Demand would be allowable, and without violating any of the requirements of the TPL Reliability Standard. The TPL Reliability Standard requires that a planner demonstrate through a valid assessment that the transmission system is planned and can be operated to supply projected Firm Demand at all demand levels over a range of forecasted system demands.[19] In addition, a planner must consider all single contingencies under Table 1, Category B and demonstrate system performance.[20] For single contingency events where system performance is not met, a planner must provide a written summary of its plans to achieve system performance

[18] NERC Data Response at 7-9.

[19] Reliability Standard TPL-002-0b, Requirement R1.

[20] Reliability Standard TPL-002-0b, Requirement R1.3.7.

including implementation schedules, in service dates of facilities and implementation lead times.[21]

15. However, if system performance is not met for any single contingency event(s) under NERC's proposed footnote 'b,' a planner could plan to interrupt some portion of Firm Demand to meet system performance requirements thereby overriding the performance requirements of the TPL Reliability Standard. For example, if a planner determines during its annual assessment that for a single bulk-power system transformer contingency other bulk-power system elements would exceed their thermal ratings, a planner would have authority under the standard to plan to interrupt Firm Demand to relieve the exceeded thermal ratings of the bulk-power system elements rather than planning the system to withstand such a single contingency and avoid shedding firm load as the performance requirements of the TPL Reliability Standard require. Therefore, without articulating some bounds on the use of the planned shedding of Firm Demand, there could be instances of multiple exceptions that could affect the robustness of the system. Further, contrary to commenters contentions, NERC's proposal, for example, has no provision to evaluate this cumulative effect of the individual decisions to shed firm.[22]

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[21] Reliability Standard TPL-002-0b, Requirement R2.

[22] BPA Comments at 5 ("The reasons for interrupting Firm Demand would be documented in studies and demonstrate that there would be no adverse impact to the BPS"); FRCC Comments at 3 ("Indeed, the transmission planning entity is responsible as part of the system assessment process under the TPL standards to test remedies to ensure

(continued…)

16. The Commission disagrees with commenters that NERC's proposed footnote 'b' will have no adverse impact on reliable planning of the bulk-power system because planning to shed Firm Demand is intended to ensure that single contingency events do not result in adverse impacts and intended to preserve bulk-power system reliability.[23] Table 1 of the TPL Reliability Standard identifies the system performance requirements or "System Limits or Impacts" that a planner must apply during its assessment of Category B, single contingency events.[24] Except in limited circumstances, if a planner determines that it must plan to interrupt Firm Demand so that it does not violate the Table 1 system performance requirements, a planner should not apply footnote 'b' as a mitigation plan to plan to operate reliably. The Commission therefore is concerned that NERC's proposal provides authority to adjust the TPL Reliability Standard and its system

that they address the problems being caused and do not cause additional problems."); and Hydro One Comments at 5 ("Loss of load is under the purview of the regulatory authority and not NERC, unless it has an adverse impact on the BES which is already taken into consideration by the TPL standards… In all cases, steps are taken in planning, design and operations of the system to ensure that Firm Demand shedding would not adversely impact the BES…").

[23] *See, e.g.,* NERC Comments at 11, TAPS Comments at 10, APPA Comments at 6.

[24] Reliability Standard TPL-002-0b, Table 1, Transmission System Standards – Normal and Emergency Conditions. Table 1 identifies the system performance requirements or "System Limits or Impacts" which are as follows: "System Stable and both Thermal and Voltage Limits within Applicable Rating", "Loss of Demand or Curtailed Firm Transfers" and "Cascading Outages."

performance requirements for each single contingency event that does not meet the system performance requirements of Table 1.

17. Further, NERC has not provided technically sound means of determining situations in which planning to interrupt Firm Demand would be allowable. While NERC expects that such determinations will be made in a stakeholder process, this provides no assurance that such a process will use technically sound means of approving or denying exceptions. The Commission concludes that the multiple stakeholder processes across the country engaging in such determinations could lead to inconsistent and arbitrary exceptions including, potentially, allowing entities to plan to interrupt any amount of Firm Demand in any location and at any voltage level.

18. While the Commission recognizes that some variation among regions or entities is reasonable given varying grid topography and other considerations, there are no technical or other criteria to determine whether varied results are arbitrary or based on meaningful distinctions. The Commission, thus, concludes that NERC's proposal lacks safeguards to ensure against inconsistent results and arbitrary determinations to allow for the planned interruption of Firm Demand.

19. A remand gives NERC and industry flexibility to develop an approach that would address the issues identified by the Commission with the proposed footnote 'b' stakeholder process including, as discussed below, definition of the process and criteria or guidelines for the process.

20. The Commission believes that, on remand, both NERC and the Commission will benefit from a more complete record regarding the electric industry's reliance on planned

Firm Demand interruptions. In response to the Commission's request to explain and quantify the extent to which Firm Demand is planned to be interrupted pursuant to currently-effective footnote 'b,' NERC explained:

> NERC and the Regional Entities have not collected statistics or preformed a survey concerning the prospective implementation of Footnote b under TPL-002-0a. During the drafting team's deliberations concerning TPL-001-2 and TPL-002-0a Footnote b, including the NERC Technical Conference on Footnote b, the informal assessments demonstrated that the use of Footnote b would not be widespread.[25]

Likewise, several commenters state that the interruption of Firm Demand is rarely needed, but provide no support for this conclusion.[26] For example, EEI asks the Commission to "recognize" that "…the actions taken as outcomes of the planning review process, are likely to identify few/isolated circumstances in which these [footnote b] provisions would be invoked…."[27] However, the Commission believes that more specific information regarding the specific circumstances and frequency with which Firm Demand is planned to be interrupted will assist both NERC in developing, and the Commission in reviewing, appropriate revisions to footnote 'b" on remand. Therefore, pursuant to section 39.2(d) of the Commission's regulations,[28] we direct NERC to identify the specific instances of any planned interruptions of Firm Demand under

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[25] NERC Data Response at 10.

[26] *See, e.g.,* FRCC Comments at 4; MISO Comments at 4; BPA Comments.

[27] EEI Comments at 2.

[28] 18 U.S.C. § 39.2(d).

footnote ‘b’ and how frequently the provision has been used. We direct NERC to use section 1600 of its Rules of Procedure to obtain information from users, owners and operators of the bulk-power system to provide this requested data.[29] NERC shall submit this information to the Commission with NERC’s footnote ‘b’ filing that addresses the concerns in this Final Rule.

21. We urge NERC to develop in a timely manner an appropriate modification that is responsive to the Commission’s directives in Order No. 693 and our concerns set forth in this Final Rule. In that regard, we require NERC to deploy its Expedited Reliability Standards Development Process to quickly respond to the remand. As the Commission noted in previous orders, the use of planned or controlled load interruption is a fundamental reliability issue and, certainty regarding the loss of non-consequential load for a single contingency event is warranted.[30] Thus, using the Expedited Standards Development Process will more rapidly bring needed certainty to this fundamental reliability issue.

22. Below we discuss three concerns: (a) jurisdictional issues, (b) lack of technical criteria, and (c) the stakeholder process. The Commission also provides guidance on other acceptable approaches.

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[29] NERC Rules of Procedure, Section 1601 (effective January 31, 2012).

[30] *North American Electric Reliability Corp.*, 130 FERC ¶ 61,200 (2010) (March 2010 Order); *North American Electric Reliability Corp.*, 131 FERC ¶ 61,231 (2010) (June 2010 Order).

A. Jurisdictional Issues

23. A number of commenters express concern that the Commission is reaching beyond its FPA section 215 jurisdiction.[31] Commenters assert that the Commission options exceed its jurisdiction involving acceptable levels and types of service. Commenters seek assurance that the Commission's proposal does not infringe on matters reserved to the States and instead "only prescribe acceptable load shedding as it pertains to wholesale customers that are in a position to select interruptible or conditional firm transmission service."[32] NARUC states that "any NERC standard for shedding distribution level load must be guided by States and that a demonstration that interruption of the load will not cause instability, uncontrolled separation, or cascading failures on the bulk system is appropriate for a NERC standard."[33] NARUC adds that specifications of what retail load and what levels of retail load can be interrupted is a State determination that is not reviewable by the Commission. TAPS agrees with NERC that issues pertaining to whether it is permissible to plan to interrupt firm load involves conflicts among federal, provincial, state, and local governing bodies.[34]

24. The Commission disagrees that it is infringing on State Commissions or overstepping jurisdictional bounds. In this Final Rule, the Commission remands NERC's

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[31] *See, e.g.,* Comments of NERC, NARUC, APPA and TAPS.

[32] NYPSC Comments at 5.

[33] NARUC Comments at 3-4.

[34] TAPS Comments at 9.

proposed footnote ‘b’ as an inadequate mechanism to address planned curtailment of firm demand and not responsive to the Commission’s directives in Order No. 693 regarding this matter. The Commission is not directing that NERC develop a specific solution or approach on remand. Thus, our remand of the NERC proposed modification to TPL-002-0b, Table 1, footnote ‘b’ is fully within the Commission’s authority pursuant to section 215(d)(4) to remand to the ERO for further consideration a modification to a proposed reliability standard that the Commission disapproves in whole or in part. Moreover, FPA section 215 gives the Commission jurisdiction over mandatory Reliability Standards to ensure reliability of the Bulk-Power System.[35] Consistent with its statutory authority, the Commission’s interest and focus in this proceeding is on the planned interruption of Firm Demand on the Bulk-Power System. The Commission views this matter in the context of Reliability Standard TPL-002-0b, which requires that in planning the system to withstand the loss of a single Bulk-Power System element, Bulk-Power System performance criteria must be met. If it is not met, a corrective action plan is required to address the Bulk-Power System performance criteria violation. Contingencies studied pursuant to Reliability Standard TPL-002-0b pertinent to Bulk-Power System facilities are subject to Commission jurisdiction under FPA section 215. In sum, the performance of the Bulk-Power System under the TPL-002-0b Reliability Standard is within the Commission’s jurisdiction.

[35] 16 U.S.C. § 824o(b)(1).

B. Lack of Technical Criteria

NOPR Proposal

25. In the NOPR, the Commission proposed to remand NERC's proposal to modify Reliability Standard TPL-002-0b, Table 1, footnote 'b.' The Commission stated that it believed that NERC's proposal does not meet the directives in Order No. 693 and the June 2010 Order and does not clarify or define the circumstances in which an entity can plan to interrupt Firm Demand for a single contingency.[36] In the NOPR the Commission expressed concern that NERC's proposed footnote 'b' lacks parameters. Without any substantive parameters governing the stakeholder process, the enforceability of this obligation by NERC and the Regional Entities would be limited to a review to ensure only that a stakeholder process occurred. The Commission noted that NERC appears to confirm this concern, as NERC explained that Regional Entities' involvement is limited to after-the-fact oversight by auditing the entity's implementation of footnote 'b' to determine if the planned interruption of Firm Demand was vetted through the stakeholder process.[37]

26. Further, in the NOPR the Commission stated that since the proposed footnote 'b' contains no constraints, it could allow an entity to plan to interrupt any amount of planned Firm Demand, in any location or at any voltage level as needed for any single contingency, provided that it is documented and subjected to a stakeholder process. The

[36] NOPR, FERC Stats. & Regs. ¶ 32,683 at P 11.

[37] *Id.* P 12.

Commission found this result remains contrary to the underlying Reliability Standard and prior Commission orders.[38] The Commission requested comment on this specific concern of the lack of technical criteria or parameters.

Comments

27. Some commenters agree with the Commission that there is lack of technical criteria to determine planned interruption of Firm Demand. For example, California SWP states that Reliability Standards "should ensure transparent criteria based on technical merits and not software limitations derived from a desire to mask [locational marginal pricing] price signals with socialized pricing or on *status quo* practices."[39] ITC believes that there is a need for defined parameters that will guide the review of exceptions and that will prevent planned interruptions from becoming commonplace.[40] Manitoba Hydro states that the characteristics of openness and transparency are indicators of a non-discriminatory planning process; however, these characteristics do not ensure that certain reliability criteria of the planned facilities will be met.[41]

28. Other commenters disagree with the Commission's concern that there is a lack of criteria to determine planned interruption of Firm Demand. NERC states that it does not believe that an exceptions process that provides defined criteria, with some allowances,

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[38] *Id.*

[39] California SWP Comments at 4.

[40] ITC Comments at 2.

[41] Manitoba Hydro Comments at 6.

could be crafted that would respect pre-existing decision making processes that occur at state and local jurisdictions. NERC argues that the decision to interrupt local load is essentially an economic decision – a quality of service issue, not a reliability issue.[42]

29. MISO disagrees that additional language would reduce the potential for inconsistent results and points out that registered entities already have many established requirements that govern the transmission planning processes.[43] MISO believes that if the Commission determines that criteria are needed, such criteria should be determined by the stakeholders in the regions though their established stakeholder processes.[44] EEI does not believe that specific criteria should be developed until a better understanding is obtained regarding the role of service interruptions as a reliability tool.[45] EEI believes that these are appropriate aspects of the NERC proposal that would be readily amenable to an initial implementation approach, followed by an adjustment period that would refine the overall process consistent with the Commission's concerns.

Commission Determination

30. We believe that openness and transparency do not alone ensure that bulk electric system performance criteria will be met to ensure system reliability. The Commission is not persuaded that developing technical criteria is unachievable. As the Commission

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[42] NERC Comments at 13.

[43] MISO Comments at 3.

[44] *Id.* at 5.

[45] EEI Comments at 10.

observed in the NOPR, NERC has thresholds in other reliability contexts, such as vegetation management pursuant to Reliability Standard FAC-003-1 which applies to all transmission lines operated at 200 kV and above. Likewise, NERC's Statement of Compliance Registry Criteria includes numerous thresholds for determining eligibility for registration.[46]

31. The Commission does not agree with EEI's recommendation to implement a stakeholder process that is absent technical criteria but then amend it later. While the Commission has, in other circumstances, approved a Reliability Standard and, as a separate action, directed NERC to develop a modification pursuant to section 215(d)(5) of the FPA, in such proceedings the Commission concluded that the proposed Reliability Standard was just, reasonable, not unduly discriminatory or preferential and in the public interest. In the immediate proceeding, however, we cannot make such a finding in light of the flawed stakeholder process provision.

32. In response to MISO's argument that such criteria should be determined by the stakeholders in the regions though their established stakeholder processes, the Commission would be amenable to such an approach if, for example, NERC and/or the Regional Entities developed an exception process that provides flexibility in decisions based on disparate topology or on other matters since they could utilize their technical

[46] *See, e.g.*, NERC Statement of Registry Criteria, section III. The Commission approved the Statement of Registry Criteria in Order No. 693. *See* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 95.

expertise to determine the reliability impact from one region to another. For these reasons, the Commission concludes that a more defined process is needed with NERC-defined technical criteria to determine planned interruption of Firm Demand. However, we conclude that the approach of allowing a decentralized process without any overarching parameters is unacceptable.

33. With regard to NERC's comment that the decision to interrupt local load is essentially an economic decision that is a quality of service issue, not a reliability issue, the Commission notes that in Order No. 693, we dismissed the argument that it may be preferable to plan the bulk electric system in such a manner that contemplates the interruption of some firm load customers in the event of a N-1 contingency, and that such interruption is based largely on the matter of economics, not reliability.[47]

C. Stakeholder Process

NOPR Proposal

34. In the NOPR, the Commission expressed concern that NERC's proposed footnote 'b' stakeholder process is insufficient to meet Order No. 693 and the June 2010 Order clarification that a regional difference, or a case-specific exception process that can be technically justified, to plan for the loss of firm services at the fringes of the systems is acceptable in limited circumstances.[48] The Commission also noted that nothing in the proposed footnote 'b' defines the stakeholder process, other than that it must be an open

[47] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1792.

[48] NOPR, FERC Stats. & Regs. ¶ 32,683 at P 19.

and transparent stakeholder process that includes addressing stakeholder comments.[49] The Commission noted that any meeting that is open to stakeholders could meet this criteria.

35. The Commission further stated that the lack of a defined stakeholder process could allow a transmission planner to develop a process that provides insufficient opportunity for stakeholder participation and transparency yet still comply with the standard. The Commission expressed its belief that nothing in the proposed footnote 'b' restricts the stakeholder process, other than that it must be an open and transparent stakeholder process that includes addressing stakeholder comments. The Commission requested comment on whether a stakeholder process is the appropriate vehicle to approve or deny exceptions to allow entities to plan to interrupt Firm Demand for a single contingency and if so, whether the proposed footnote 'b' would require any stakeholder due process.

Comments

36. Several commenters believe that NERC's proposed stakeholder process is the appropriate venue to approve or deny exceptions to interrupt planned Firm Demand. NERC and other commenters contend that building on existing stakeholder processes is appropriate, rather than creating new, duplicative processes. While EEI, APPA, and TAPS concur with or acknowledge the Commission's concerns about the inadequacy of the proposed stakeholder process, they nonetheless urge the Commission to approve

[49] *Id.* P 20.

NERC's proposal stating that it reflects the considered expertise that instances of planned load shed are uncommon and not amenable to a one-size-fits-all approach.[50] NERC believes the introduction of an additional planning process may contribute to further delays and regulatory confusion. NERC states that "keeping decision-making with those most impacted by decisions regarding reliability and costs, lack of jurisdictional authority, and the existence of established open and transparent stakeholder processes – are the reasons NERC did not create a new stakeholder process."[51]

37. Duke Energy believes that the current Order No. 890-type process involving the local transmission planning collaborative is the appropriate stakeholder process. Duke Energy suggests that footnote 'b' should be revised to include a local regulatory authority process as the appropriate stakeholder process to allow entities to plan to interrupt Firm Demand for a single contingency. According to Duke Energy, in such a process a transmission planner would submit its plan to interrupt Firm Demand for a single contingency to its local regulatory authority that has jurisdiction over quality of service to local load prior to any actual interruption of Firm Demand.

38. BPA states that the stakeholder process will keep the decision local, where the parties involved understand the different factors that must be considered in deciding the

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[50] *See, e.g.*, EEI Comments at 3, TAPS Comments at 5, APPA Comments at 3.

[51] NERC Comments at 12.

proper path forward.[52] APPA maintains that these processes impose due process requirements on the transmission planner, including participation in an open and transparent stakeholder process that considers stakeholder comments.[53]

39. FRCC disagrees with the Commission that enforceability is limited since the process requires development of a record documenting the decisions and stakeholder comments and planning authority responses. According to FRCC, the result will provide NERC and the Commission substantive and procedural grounds to assess whether sufficient consideration was given to maintaining reliability.[54]

40. Some commenters believe that NERC's proposed stakeholder process is not the appropriate vehicle to approve or deny exceptions to interrupt planned Firm Demand. ITC argues that the stakeholder process is inadequately undefined to ensure that planned Firm Demand interruptions are kept to a minimum. Manitoba Hydro indicates that by acknowledging an exception for interruptible Firm Demand, NERC appears to recognize that the right to interrupt is not solely a reliability issue, but also a commercial or legal issue based on contractual rights.[55]

41. While TAPS encourages the Commission to accept NERC's proposed footnote 'b,' it shares the NOPR's concerns about the adequacy of the open and transparent

[52] BPA Comments at 4.

[53] APPA Comments at 5.

[54] FRCC Comments at 3.

[55] Manitoba Hydro Comments at 5.

stakeholder process and has argued for a decision-making role for transmission-dependent utilities in the Order No. 890 and Order No. 1000 planning processes to ensure that stakeholder processes do not result in a presentation of a decision followed by the transmission provider simply "rubber-stamping" the decision.[56] If the Commission determines that these objectives cannot be accomplished without more robust action from the Commission in this proceeding, TAPS urges the Commission not to remand the proposed footnote 'b,' but instead to accept NERC's proposal and direct NERC to submit a further modified footnote 'b' to address the parameters of the "open and transparent stakeholder process that includes addressing stakeholder comments."[57]

Commission Determination

42. The Commission is not persuaded that the stakeholder process is adequately defined. The Commission is concerned that the stakeholder process could undermine the system performance criteria of TPL-002-0b Reliability Standard. As the Commission stated in Order No. 693, one of the key reliability objectives of the TPL Reliability Standard is that the system can be operated following the loss of one element and supply projected firm customer demands and projected firm transmission services at all demand levels over the range of forecast system demands.[58] The Commission finds that the stakeholder process without appropriate parameters is inconsistent with the reliability

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[56] TAPS Comments at 5.

[57] *Id.* at 11.

[58] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1771.

objective to supply projected firm customer demands for the loss of one element. While the Reliability Standard requires that the system is planned so that the system can be operated following the loss of one element and supply projected firm customer demands, the proposed stakeholder process could defeat this by allowing a transmission planner to plan to shed as much load as needed so that the system can be operated to supply whatever customers remain.

43. The Commission agrees with TAPS to the extent it observes that the proposal could allow a transmission planner to utilize a new or existing stakeholder process that provides insufficient opportunity for a stakeholder to provide meaningful input. We conclude that the stakeholder process with no criteria to objectively assess whether varied results are arbitrary or based on meaningful differences is unjust, unreasonable, unduly discriminatory or preferential, and not in the public interest. Nothing in proposed footnote ‘b’ defines the stakeholder process, other than it must be an open and transparent stakeholder process that includes addressing stakeholder comments.

44. The Commission is not persuaded by FRCC’s comment that enforceability is not limited by proposed footnote ‘b’ and that development of a record will provide NERC “substantive and procedural” grounds to assess the outcome of the process. Neither FRCC nor any other commenter identifies the minimum procedural safeguards to assure an adequate level of stakeholder participation and consideration of stakeholder comment in the decision-making process. Moreover, even NERC, which states that it can conduct

after-the-fact audits, indicates that such audits would not explore substantive adequacy or the reliability basis for a decision to plan to shed Firm Demand.[59] Further, the Commission is not persuaded by APPA and BPA comments that local stakeholder participation and due process requirements imposed on the transmission planner are sufficient. Rather, the Commission believes that if a transmission planner invokes a process that provides for minimal stakeholder involvement, it could argue that it satisfied the provision, even if the transmission planner is the ultimate decision maker and simply 'rubber stamps' its own proposal to interrupt planned Firm Demand.

D. Guidance on Acceptable Approaches to Footnote 'b'

45. The Commission proposed three options in the NOPR for further guidance on acceptable approaches to footnote 'b.' In addition, the Commission requested comment on other potential options to solve the concerns outlined in the NOPR.

1. Existing Protocols to Develop Criteria/Quantitative Limits

46. In the NOPR, the Commission acknowledged that NERC considered a variety of limits but observed that NERC's establishment of some form of criteria for planning to interrupt Firm Demand could be an acceptable approach for footnote 'b.' The Commission requested comment on whether existing protocols such as the Department of Energy's Electric Emergency Incident and Disturbance Report (Form OE-417), which requires an entity to report a certain amount of uncontrolled loss of firm system loads, or

[59] NERC Data Response at 7-9.

NERC's Statement of Compliance Registry Criteria could provide guidance to NERC to devise criteria.

Comments

47. Commenters were unanimous that the examples of existing protocols would not be beneficial to devise criteria. NERC and others state that any bright-line megawatt limit would be inappropriate because the bright-line would be arbitrary.[60] Some commenters do not believe that existing protocols, such as the requirement in Form OE-417 should be used to determine criteria related to planned loss of Firm Demand.[61]

48. BPA, ITC, and Duke Energy comment that setting a quantitative limit would push transmission planners to plan to meet such a limit for a single contingency in all cases. Currently, transmission planners start from the premise that no load should be interrupted in the event of a single contingency. ITC believes that including such an acceptable lost load criterion as an option could lead to that option being chosen as the "default solution," i.e., allowing for a certain amount of acceptable interruption of Firm Demand without a stakeholder exception review process.[62] In the same vein, Duke indicates that a specific megawatt threshold may prohibit certain interruptions of Firm Demand that would be acceptable from a quality of service and local consequences perspectives.[63]

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[60] NERC Comments at 14.

[61] ITC Comments at 5; *see also* Hydro One and IESO Comments.

[62] ITC Comments at 5.

[63] Duke Comments at 6.

Commission Determination

49. The Commission is persuaded by the commenters that Form OE-417 or the Registry Criteria are not, by themselves, beneficial to use to devise criteria. The Commission also agrees that a bright-line criteria by itself does not present a viable option and would have the potential to constitute an acceptable *de facto* interruption and become commonplace to plan to interrupt Firm Demand. For example, if the bright-line criteria included up to 50 MW of planned interruptible Firm Demand under proposed footnote 'b', then planners may choose to automatically shed up to 50 MW of load as their first course of action for any single contingency event that would cause a violation of system performance criteria. This is not an acceptable outcome.

2. A Blend of Quantitative and Qualitative Thresholds

50. The Commission also sought comment on whether a blend of quantitative and qualitative thresholds to be used to interrupt planned Firm Demand would be an appropriate option for providing criteria that would be generally applicable, but also for allowing for certain cases that may exceed the criteria. For example, a Reliability Standard could require a process with a quantitative limitation on how much Firm Demand could be planned for interruption and the standard could provide an exception process where a registered entity would submit documents and explanation to the ERO or a Regional Entity for approval based upon certain considerations.[64] The Commission

[64] NOPR, FERC Stats. & Regs. ¶ 32,683 at P 18.

suggested that setting generally applicable criteria for when an applicable entity can plan to shed Firm Demand, coupled with an exceptions process overseen by NERC and the Regional Entities, could mean that few exception requests must be processed by NERC and the Regional Entities.[65] The Commission observed in the NOPR that this approach may satisfy the need for technical criteria while accounting for NERC's concerns about the difficulty of developing a one-size-fits-all criterion for limiting planned Firm Demand interruptions and the appropriateness and feasibility of managing and actively participating in each planning process.

Comments

51. California SWP indicates that standards must constrain the use of firm load shedding as a reliability solution in transmission planning and at the same time, require a transparent and clearly defined stakeholder process to support any such planned use of load shedding for single contingency events.[66] BPA suggests that, if the Commission does set a quantitative limit on planned interruption of Firm Demand, a limit based on a fraction of aggregated normal peak load would be one option that may be more effective and adaptable to all sizes of utilities.[67]

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[65] *Id.* P 27.

[66] California SWP Comments at 2.

[67] BPA Comments at 4.

52. Other commenters disagree that a blend is a good option. NARUC indicates that rather than inventing another stakeholder process by requiring NERC to set specific quantitative or qualitative requirements for distribution load shedding, NERC should look to State commissions and existing State curtailment plans to guide load shedding in contingency planning.[68] Duke Energy submits that a blend of quantitative and qualitative thresholds does not provide enough flexibility to permit the qualitative assessment of the loads and locations for which transmission planners may interrupt under their exercise of footnote 'b' because a blended threshold may still rely too heavily on a quantitative threshold for planned interruption of Firm Demand.[69] FRCC states it is not feasible to develop a single quantitative rule that would apply equitably to all stakeholders and regions.[70]

53. EEI believes that adopting a process that would provide greater clarity, reporting, and refinement would provide the specific information on the extent that the footnote 'b' issue presents itself. EEI also agrees with NERC that efforts to create a one-size-fits-all approach have less value than a process that ensures openness and transparency.

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[68] NARUC Comments at 3.

[69] Duke Energy Comments at 7.

[70] FRCC Comments at 7.

Commission Determination

54. The Commission believes that setting a quantitative and qualitative threshold in developing a limited exception for planned interruption of Firm Demand may be a workable solution. First, qualitative thresholds could be used to overcome the concern discussed immediately above regarding the quantitative threshold becoming an acceptable *de facto* interruption of planned Firm Demand. By utilizing a blend, the planner must also meet the qualitative threshold which could consist of, for example, the submittal of documents and explanation to the entity ultimately deciding whether the planned load shed is acceptable. For example, if 100 MW of planned Firm Demand was permitted to be interrupted, the planner could not automatically and unilaterally shed up to 100 MW of planned Firm Demand each time system performance criteria would be violated. Under the blend concept, the Commission envisions that the planner would consider up to 100 MW of planned Firm Demand interruption along with other options to resolve the system performance criteria violation and submit its documentation and explanation to the entity deciding whether the planned load shed is acceptable. The concept of a blend of thresholds would prevent an acceptable *de facto* interruption of planned Firm Demand and avoid the difficulty of developing a one-size-fits-all criterion for limiting planned Firm Demand interruptions, but still allow for those limited circumstances to be reviewed in an exception process where a limited amount of planned interruption of Firm Demand may be acceptable.

55. We believe it is appropriate for the Regional Entities, with NERC as the final authority, to make determinations under a “blended” exception process. First, NERC and

the Regional Entities provide both objectivity in the decision-making process as well as the necessary reliability-focused expertise. Second, this should not overly burden NERC or Regional Entity resources as utilization of the planned load shed exception is – and would be – rarely utilized.[71] Further, we are not persuaded by the assertion that NERC would be conflicted as the ERO and also inserting itself in the process. NERC's ERO role would continue, in coordination with its current responsibilities in implementing other exceptions such as the Technical Feasibility Exception process under the Critical Infrastructure Protection Reliability Standards.

56. The Commission does not agree with BPA's suggestion of using quantitative thresholds based on a fraction of aggregated normal peak load. BPA's suggestion attempts to address the concerns of commenters that a bright-line threshold must be established that would be a one-size-fits-all criteria. For example, instead of a megawatt bright-line threshold for all entities, the ERO could establish a threshold based on a percentage of aggregated normal peak load. The Commission believes that it would be difficult to demonstrate that adoption of BPA's suggestion would be just and reasonable, not unduly discriminatory or preferential and in the public interest. If criteria were established that permitted a percentage of aggregated normal peak load as an acceptable threshold for planned interruption of Firm Demand, even a small percentage could equate

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[71] *See, e.g.,* FRCC Comments at 4; MISO Comments at 4; BPA Comments.

to entire towns, cities or regions of load.[72] The Commission, therefore, does not support the planned interruption of Firm Demand based on a fraction of aggregated normal peak load. The Commission believes that an appropriate mechanism would be based on impact studies that consider minimizing planned interruption of Firm Demand within, and adjacent to, communities and small localities.

57. The Commission offers guidance to NERC to consider the option of a blend of quantitative and qualitative thresholds. An example of a qualitative threshold could include identifying geographical or topological "fringes of the system." While interruption at the fringes of the system may be expected by some consumers, not all customers necessarily have that same expectation. For example, we don't expect that many water treatment facilities or telecom switching stations normally plan to be interrupted for single contingency events.[73] While the Commission has offered one example of a qualitative threshold, NERC may explore other qualitative thresholds on remand. The Commission believes that a blend of quantitative and qualitative thresholds coupled with an exception process overseen by NERC and the Regional Entities would be a reasonable option to allow for the limited interruption of planned Firm Demand.

[72] For example, the PJM aggregated normal system peak load is approaching 160,000 MW, so a one percent threshold would equate to allowance of planned interruption for a single contingency of up to 1600 MW of load, which is the size of some entire towns, cities or regions.

[73] While we anticipate that such facilities are prepared for distribution-level blackouts, we are not aware that they are prepared for a transmission-level blackout.

Accordingly, the Commission directs the ERO to consider some blend of quantitative and qualitative thresholds.

3. <u>Customer or Community Consent</u>

58. In the NOPR the Commission also requested comment on whether a feasible option would be to revise footnote 'b' to allow for the planned interruption of Firm Demand in circumstances where the "transmission planner can show that it has customer or community consent and there is no adverse impact to the Bulk-Power System."[74] The Commission suggested that this would not require affirmative consent by every individual retail customer, but would recognize that either group would need to be adequately defined. The Commission requested comments on who might be able to represent the customer or community in this option and how customer or community consent might be demonstrated.[75] The Commission also requested comment on how it would be determined that firm demand shedding with customer consent would not adversely impact the Bulk-Power System. Additionally, the Commission requested comment on whether a customer who would otherwise consent to having its planning authority or transmission planner plan to interrupt Firm Demand pursuant to this option could instead select interruptible or conditional firm service under the tariff to address cost concerns.

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[74] NOPR, FERC Stats. & Regs. ¶ 32,683 at P 28.

[75] *Id.*

Comments

59. Several commenters agreed with the Commission that the customer or community consent should be required. ITC believes the customers or entities should be involved in a stakeholder process such as a representative group for the affected load or customers (community representatives or a separate load serving entity where the transmission provider is not an integrated utility), the public service/utility regulatory commission for the affected load, the RTO or ISO for the affected area, and any other affected entity. California SWP also supports notice to and consent of loads (or their wholesale representatives) that are planned to be interrupted for the loss of a single element.[76] In its comments, California SWP explains that it was "surprised to learn that in lieu of transmission upgrades, [its transmission planner] relied on interruption of SWP's large firm pump loads supposedly receiving the same California Independent System Operator (CAISO) transmission service as provided to SCE loads. At that time, SWP was not consulted about the planned curtailment of its firm loads as an alternative to a transmission upgrade, and thus had no opportunity to correct this error."[77]

60. Other commenters disagree that customer or community consent should be required. NERC states that it has no relationship with retail customers and, therefore, has no mechanism to bring retail customers into the conversation. NERC adds that both

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[76] California SWP Comments at 4.

[77] *Id.* at 2-3.

wholesale and retail customers are already involved in state processes which provide a forum for them to be heard.

61. Hydro One and the IESO submit that customer interests are managed by the relevant regulatory authority and consent is through regulatory approval. In all cases, steps are taken in planning, design, and operations of the system to ensure that Firm Demand shedding would not adversely impact the bulk electric system in addition to the fact that the customer also has other options such as to select interruptible service. NYPSC recommends that the Commission only prescribe acceptable load shedding as it pertains to wholesale customers that are in a position to select interruptible or conditional firm transmission service under Commission-approved tariffs.

62. FRCC states that the evaluation of the possible use of interruptible or conditional firm service instead of planned interruptions of Firm Demand is not warranted. According to FRCC, the adoption of a Firm Demand interruption alternative would inherently entail customer benefits from foregone project costs and the non-incurrence of environmental and other impacts. The customers would also generally enjoy a higher quality of service than traditional interruptible or conditional firm. Consequently, FRCC believes that applying any such rate in place of Demand interruption would present imponderable issues of quantification and application.

63. BPA does not believe that this proceeding is appropriate to decide issues related to service choice. BPA argues that the Commission has determined that the rate for conditional firm service be the same as the firm rate. BPA does not anticipate that the interruption of Firm Demand would occur on a frequent basis, if at all. Thus, BPA does

not believe that a customer should pay a different transmission rate under these circumstances. APPA states that footnote ‘b’ arms wholesale transmission customers and communities served at retail with information and studies prepared by the transmission planner, documenting the specific circumstances (i.e., specific Bulk Electric System Contingency events) under which interruption of Firm Demand may be needed to address bulk electric system performance requirements.

Commission Determination

64. We understand NERC’s position that as the entity that addresses Bulk-Power System reliability, it does not have a mechanism to coordinate with customers. Likewise, how to define customers and community decisions and engage them in the NERC process could be challenging.[78]

65. At the same time, California SWP provides a compelling example of how a customer can be adversely affected by planned load shedding for Firm Demand if it was unaware its load would be interrupted until its load was actually shed. In contrast to California SWP’s experience, a customer should have notice and understanding that the transmission planner plans to curtail certain Firm Demand in the event of a single

[78] As suggested in the NOPR, customer or community consent would not require affirmative consent by every individual retail customer, but the process NERC developed would recognize that either group would need to be adequately defined. We note that, although NERC comments that it addresses Bulk-Power System reliability, the process that NERC proposes will impact firm load service to retail customers.

contingency indentified in the system modeling under NERC's Transmission Planning requirements. NERC should consider these matters on remand.[79]

Summary

66. In sum, the Commission remands the proposed footnote 'b' and directs NERC to revise its proposal to address the Commission's concerns described above, subject to consideration of the additional guidance provided in this Final Rule.

67. As stated in the NOPR, NERC will need to support the revision to footnote 'b.' If there is a threshold component to the revised footnote, NERC would need to support the threshold and show that instability, uncontrolled separation, or cascading failures of the system will not occur as a result of planning to shed Firm Demand up to the threshold. In addition, if there is an individual exception option, the applicable entities should be required to find that there is no adverse impact to the Bulk-Power System from the exception and that it is considered in wide-area coordination and operations. Further, the Commission believes that any exception should be subject to further review by the Regional Entity or NERC.

III. Information Collection Statement

68. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an

[79] We will not consider the tariff-related comments as they are beyond the scope of this rulemaking.

agency.[80] The information contained here is also subject to review under section 3507(d) of the Paperwork Reduction Act of 1995.[81]

69. As stated above, the subject of this Final Rule is NERC's proposed modification to Table 1, footnote 'b' applicable in four TPL Reliability Standards. This Final Rule remands the footnote 'b' modification to NERC. By remanding footnote 'b' the applicable Reliability Standards and any information collection requirements are unchanged. Therefore, the Commission will submit this Final Rule to OMB for informational purposes only.

70. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: data.clearance@ferc.gov, phone: (202) 502-8663, or fax: (202) 273-0873].

IV. Environmental Analysis

71. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[82] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment.

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[80] 5 CFR § 1320.11.

[81] 44 U.S.C. § 3507(d).

[82] *Regulations Implementing the National Environmental Policy Act of* 1969, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986-1990 ¶ 30,783 (1987).

Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[83] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act

72. The Regulatory Flexibility Act of 1980 (RFA)[84] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[85] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.[86] The RFA is not implicated by this Final Rule because the Commission is remanding footnote 'b' and not proposing any modifications to the existing burden or reporting requirements. With no changes to the Reliability Standards as approved, the Commission certifies that this

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[83] 18 CFR § 380.4(a)(2)(ii).

[84] 5 U.S.C. § 601-612.

[85] 13 CFR § 121.201.

[86] *Id.* n.22.

Final Rule will not have a significant economic impact on a substantial number of small entities.

VI. Document Availability

73. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

74. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

75. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

VII. Effective Date and Congressional Notification

76. These regulations are effective [insert date 60 days from publication in **FEDERAL REGISTER**]. The Commission has determined, with the concurrence of the

Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

By direction of the Commission. Commissioner Norris is dissenting in part and concurring in part with a separate statement attached.

(S E A L)

Kimberly D. Bose,
Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning Reliability Standards Docket No. RM11-18-000

(Issued April 19, 2012)

NORRIS, Commissioner, *dissenting in part and concurring in part*:

The continued implementation and evolution of the mandatory reliability standards program enacted by Congress in 2005 has been at the forefront of our agenda since I arrived at the Commission in 2010. As we have grappled with the difficult issues raised by proposed new or revised standards, and as I have discussed these issues with regulated industry, state regulators, and the public, I have consistently heard a common theme: mandatory reliability standards come with costs that consumers ultimately must bear.

As I have thought about this issue, it has become clear to me that in any discussion of a new or revised mandatory reliability standard, there is always a tradeoff between the level of reliability to be achieved by that standard and the costs that the standard will impose. However, that tradeoff is rarely discussed explicitly in the standards development process or during the Commission's review of standards. But, we know that it is an implicit consideration of entities participating in the standards development process. I believe it is more appropriate to make those considerations, where they are relevant, explicit. Therefore, I have advocated for an open dialogue between NERC, the industry, and the Commission to consider the connection between the mandatory standards we approve to maintain and improve the reliability of the Bulk Power System and the costs required to meet those standards.

However, I have perceived some hesitancy in openly addressing costs when considering reliability matters. This is not surprising, as there are no easy answers to these tough questions, and regulators and industry charged with assuring reliability will always be hesitant to be perceived as sacrificing reliability in an effort to save on costs. While I am not advocating for a cost-benefit threshold for approving reliability standards, I do not believe that we can ignore the costs of proposed mandatory reliability standards as we consider whether they are "just, reasonable, not unduly discriminatory or preferential, and in the public interest".[1] These are issues with real world implications,

[1] *See* 16 U.S.C. 824o(d)(2).

not just for the reliability and security of our Nation's electric grid, but for the day-to-day struggles of local communities to balance the economic realities of many competing obligations.

I am compelled to raise these issues in this proceeding because I believe that the Transmission Planning (TPL) Reliability Standard footnote 'b' addressed in today's order presents a stark example of the tradeoffs that sometimes must be made between increasing levels of reliability and the costs that come with achieving them. As such, I hope my comments today will help generate a dialogue on how economics and reliability fit together when considering mandatory reliability standards.

In today's order, I agree with the majority's decision to remand proposed TPL footnote 'b' because it is vague, potentially unenforceable, and lacks adequate safeguards to determine when planning to shed firm load would be permitted. However, I am concerned that, in allowing for an exception to the TPL standards requirement that firm load must be maintained under N-1 scenarios, the order does not sufficiently recognize that this is both an economic and reliability issue, and must allow for a balancing of the economic and reliability considerations involved.

There may be cases where planning to avoid shedding firm load in all N-1 scenarios will impose significant costs on customers, with perhaps little added reliability benefit for those customers. In such instances, I believe that wholesale transmission customers and local communities with retail load service should be empowered to consider the economic tradeoffs between incurring costs to avoid shedding firm load versus planning to shed firm load, as long as that decision does not adversely impact the reliability of the Bulk Power System. Simply put, if a customer seeks to avoid significant costs, and can do so without impacting its neighbors, the customer should be making that decision. Today's order fails to adequately acknowledge the economic consequences of having to invest in significant facility upgrades to avoid shedding firm load under certain N-1 scenarios that may be rare or unlikely and that would have only local impacts.[2]

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[2] *Transmission Planning Reliability Standards*, Order No. 762, 139 FERC ¶ 61,060, at P 33 (2012) ("With regard to NERC's comment that the decision to interrupt local load is essentially an economic decision that is a quality of service issue, not a reliability issue, the Commission notes that in Order No. 693, we dismissed the argument that… such interruption is based largely on the matter of economics, not reliability.") I also note that the brief Commission findings in Order No. 693 failed to acknowledge or sufficiently address this issue, leaving the uncertainty we are still faced with today. *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 1791-1794 (2007).

Accordingly, in my view, the Commission should have directed NERC to revise footnote 'b' to address two broad concerns. First, wholesale transmission customers and retail load should have the ability to choose whether to shed firm load during an N-1 contingency where that decision will not adversely impact the Bulk Power System. Second, the decision to shed firm load must be validated to ensure that there is no adverse impact on the Bulk Power System. Absent this reliability check, the planning of firm load shedding should not be permitted, because reliability of the Bulk Power System is paramount. While NERC, the Regional Entity, and/or the local planning authority must be involved in the reliability check, these entities would not be expected to be involved in the economic decision.

Additionally, I agree with various comments filed in response to the NOPR that firm load shedding is and should be used rarely or infrequently. I do not expect that any new process that NERC may propose to determine whether firm load shedding is permitted would result in a rush by entities seeking to plan to shed firm load. In other words, I do not expect this exception to "swallow the rule" under the TPL standards that firm load may not be planned to be shed for N-1 contingencies.

Finally, the concerns I note above regarding the failure to consider both the economic and reliability aspects of a decision to plan to shed firm load extend to the specific guidance provided in the order. The guidance in the order with respect to what would constitute an allowable exception fails to provide a realistic means for entities to balance these economic and reliability considerations. Instead, I would have provided that an entity could submit its plan to shed firm load for a single contingency to its relevant regulatory authority or governing body prior to any actual interruption.[3] The politically accountable regulatory authority or governing body would have then made the determination, based upon economics and in the best interests of its customers, as to whether firm load shedding should be permitted. Those determinations would be subject to oversight and review by NERC, the Regional Entity, and/or the planning authority to ensure that they will not adversely impact the Bulk Power System.[4]

[3] *See e.g.*, Duke Energy Corporation Dec. 22, 2011 Comments, Docket No. RM11-18-000.

[4] NERC may propose an alternative to Commission guidance that is equally efficient and effective at addressing the Commission's reliability concerns. Order No. 693 at P 31.

For these reasons, I respectfully dissent in part and concur in part.

____

John R. Norris, Commissioner

Document Content(s)

Standards Announcement

Project 2010-11 – TPL Table 1 Order
TPL-002-1c, footnote ‘b’ and TPL-001-2a, footnote 12

Initial Ballot open through 8 p.m. Monday, November 19, 2012

Now Available

A single initial ballot is open for revisions to a single footnote that is incorporated into two standards (**TPL-002-1c**– System Performance Following Loss of a Single BES Element for footnote ‘b’, and **TPL-001-2a** – Transmission System Planning Performance Requirements for footnote 12) through **8 p.m. Eastern Monday, November 19, 2012.**

Please note that, aside from the proposed revisions to the footnote and changes to conform the Enforcement Dates section to the current language approved by NERC legal to cover all of the jurisdictions in which NERC standards are mandatory, no other revisions have been made to either standard. The scope of the drafting team’s assignment is limited to addressing changes to the single footnote.

Instructions
Members of the ballot pools associated with this project may log in and submit their votes for the footnote in both standards by clicking here.

Next Steps
The drafting team will consider all comments received during the formal comment period and initial ballot and, if needed, make revisions to the footnote. If the comments do not show the need for significant revisions, the footnote will proceed to successive ballot.

Background
FERC Order No. 762, issued April 19, 2012, remanded TPL-002-0b to NERC as vague, unenforceable and not responsive to the previous Commission directives on this matter. The Standards Committee directed the Standards Drafting Team (SDT) to revise footnote ‘b’ in accordance with the directives of Orders No. 693 and 762. The SDT was also charged with revising the corresponding footnote 12 of TPL-001-2 in order to prevent the remand of TPL-001-2.

In revising the footnotes, the SDT adopted a philosophy of minimal changes to the actual footnote itself. This was done to minimize confusion as to what was changed, for ease of reading and following the footnote, and for formatting within the actual standards documents. Instead, the SDT revised the footnote by developing an attachment to the footnote containing changes in response to the Commission orders. It should be noted that attachments to standards are an extension of the Requirements and thus are binding to applicable entities.

Project 2010-11 is an important part of the ERO's strategic goal to be responsive to regulatory authority directives in an expeditious manner in order to reduce the amount of standards-related directives and to provide an adequate level of reliability.

Additional information can be found on the project page.

Standards Development Process

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For more information or assistance, please contact Wendy Muller,
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Standards Announcement

Project 2010-11– TPL Table 1 Order
TPL-002-1c, footnote ‘b’ and TPL-001-2a, footnote 12

Formal Comment Period Open: October 5 – November 19, 2012

Upcoming
Initial Ballot: November 9 – November 19, 2012

Now Available

A formal comment period for a revisions to a single footnote that is incorporated into two standards (**TPL-002-1c**– System Performance Following Loss of a Single BES Element as footnote ‘b’, and **TPL-001-2a** – Transmission System Planning Performance Requirements as footnote 12) is open through **8 p.m. Eastern on Monday, November 19, 2012.**

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Instructions for Joining Ballot Pool(s)

Registered Ballot Body members must join the ballot pool to be eligible to vote in balloting of a footnote that is included in standard **TPL-002-1c** as footnote ’b’, **TPL-001-2a** as footnote 12. Registered Ballot Body members may join the ballot pool at the following page: Join Ballot Pool

During the pre-ballot window, members of the ballot pool may communicate with one another by using the “ballot pool list server.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list server.) The ballot pool list server for this ballot pool is: bp-2010-11_TPL_ftb_in@nerc.com

The ballot pool is open **through 8 a.m. Eastern on Monday, November 5, 2012.**

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Monday, November 19, 2012.** Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

A single initial ballot for the footnote in both standards will be conducted Friday, November 9, 2012 through 8 p.m. Monday, November 19, 2012.

Background

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Standards Announcement

Project 2010-11– TPL Table 1 Order

TPL-002-1c, footnote ‘b’ and TPL-001-2a, footnote 12

Formal Comment Period Open: October 5 – November 19, 2012

Upcoming
Initial Ballot: November 9 – November 19, 2012

Now Available

A formal comment period for a revisions to a single footnote that is incorporated into two standards (**TPL-002-1c**– System Performance Following Loss of a Single BES Element as footnote ‘b’, and **TPL-001-2a** – Transmission System Planning Performance Requirements as footnote 12) is open through **8 p.m. Eastern on Monday, November 19, 2012.**

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Standards Announcement

Project 2010-11 – TPL Table 1 Order
TPL-002-1c, footnote ‘b’ and TPL-001-2a, footnote 12

Initial Ballot Results

Now Available

The initial ballot window for the revisions to a single footnote that were incorporated into two standards (**TPL-002-1c**– System Performance Following Loss of a Single BES Element as footnote ‘b’, and **TPL-001-2a** – Transmission System Planning Performance Requirements as footnote 12) concluded Monday, November 19, 2012.

Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results.

Approval
Quorum: 80.45% (updated) Approval: 56.18%

Next Steps
The drafting team will consider all comments received during the formal comment period and initial ballot and, if needed, make revisions to the footnote. If the drafting team makes substantive revisions, the drafting team will submit the revised footnote and consideration of comments received for a quality review prior to posting for a parallel formal 30-day comment period and successive ballot.

Background
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Ballot Results	
Ballot Name:	Project 2010-11 TPL footnote b Initial Ballot October 2012_in
Ballot Period:	11/9/2012 - 11/19/2012
Ballot Type:	Initial
Total # Votes:	288
Total Ballot Pool:	358
Quorum:	**80.45 % The Quorum has been reached**
Weighted Segment Vote:	56.18 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	102	1	40	0.563	31	0.437	9	22
2 - Segment 2.	10	0.9	4	0.4	5	0.5	1	0
3 - Segment 3.	82	1	32	0.561	25	0.439	8	17
4 - Segment 4.	25	1	5	0.313	11	0.688	5	4
5 - Segment 5.	73	1	29	0.592	20	0.408	12	12
6 - Segment 6.	48	1	16	0.516	15	0.484	7	10
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.5	5	0.5	0	0	0	3
9 - Segment 9.	3	0.2	0	0	2	0.2	0	1
10 - Segment 10.	7	0.6	6	0.6	0	0	0	1
Totals	**358**	**7.2**	**137**	**4.045**	**109**	**3.156**	**42**	**70**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1		Vijay Sankar	Affirmative	
1	Ameren Services	Kirit Shah	Abstain	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Negative	
1	Avista Corp.	Scott J Kinney	Affirmative	

1	Balancing Authority of Northern California	Kevin Smith	Negative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher		
1	Bonneville Power Administration	Donald S. Watkins	Negative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Maine Power Company	Joseph Turano Jr.	Negative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Tallahassee	Daniel S Langston		
1	Clark Public Utilities	Jack Stamper	Negative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Corporate Risk Solutions, Inc.	Joseph Doetzl		
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker	Negative	
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils		
1	Entergy Transmission	Oliver A Burke	Abstain	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	FortisBC	Curtis Klashinsky		
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Negative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Keys Energy Services	Stanley T Rzad	Negative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Negative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Negative	
1	MEAG Power	Danny Dees	Negative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	
1	New York Power Authority	Bruce Metruck	Negative	
1	Northeast Missouri Electric Power Cooperative	Kevin White		
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins	Negative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	

1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Abstain	
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Negative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo		
1	Snohomish County PUD No. 1	Long T Duong	Negative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	
1	South Mississippi Electric Power Association	Rodney A. Wilson	Affirmative	
1	Southern California Edison Company	Steven Mavis	Negative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Brandy A Dunn	Negative	
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	
2	ISO New England, Inc.	Kathleen Goodman	Negative	
2	Midwest ISO, Inc.	Marie Knox	Negative	
2	New Brunswick System Operator	Alden Briggs	Negative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Negative	
3	Ameren Services	Mark Peters	Abstain	
3	APS	Steven Norris	Negative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Robert Lafferty		
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Green Cove Springs	Gregg R Griffin		
3	City of Homestead	Orestes J Garcia		
3	City of Redding	Bill Hughes	Abstain	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Colorado Springs Utilities	Charles Morgan		
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock		
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr		

3	Entergy	Joel T Plessinger	Abstain	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey	Negative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Negative	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Negative	
3	Modesto Irrigation District	Jack W Savage	Negative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Negative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera		
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Negative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Gary Clear		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Negative	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Negative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	
3	Salt River Project	John T. Underhill	Abstain	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	Snohomish County PUD No. 1	Mark Oens	Negative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Negative	
4	American Municipal Power	Kevin Koloini		
4	Arkansas Electric Cooperative Corporation	Ronnie Frizzell		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Abstain	
4	City Utilities of Springfield, Missouri	John Allen	Negative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	

4	Consumers Energy	David Frank Ronk	Abstain	
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Negative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	
4	South Mississippi Electric Power Association	Steven McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Negative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas	Abstain	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	
5	City of Redding	Paul A. Cummings	Abstain	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Abstain	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Electric Power Supply Association	John R Cashin	Abstain	
5	Energy Services, Inc.	Tracey Stubbs		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Negative	
5	MidAmerican Energy Co.	Neil D Hammer	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Wayne Sipperly	Negative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Oklahoma Gas and Electric Co.	Kim Morphis	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		

5	Platte River Power Authority	Roland Thiel	Negative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	
5	Salt River Project	William Alkema	Abstain	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	
5	Southern California Edison Company	Denise Yaffe	Negative	
5	Southern Company Generation	William D Shultz		
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer		
5	Tennessee Valley Authority	David Thompson	Negative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Xcel Energy, Inc.	Liam Noailles	Negative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	APS	Randy A. Young		
6	Associated Electric Cooperative, Inc.	Brian Ackermann		
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Negative	
6	City of Redding	Marvin Briggs	Abstain	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn	Abstain	
6	Florida Power & Light Co.	Silvia P. Mitchell		
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Manitoba Hydro	Daniel Prowse	Negative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	Modesto Irrigation District	James McFall	Negative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Kelly Cumiskey	Abstain	
6	Platte River Power Authority	Carol Ballantine	Negative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Negative	
6	Salt River Project	Steven J Hulet	Abstain	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	
6	South Mississippi Electric Power Association	Joel Rogers		
6	Southern California Edison Company	Lujuanna Medina	Negative	

6	Southern Company Generation and Energy Marketing	John J. Ciza		
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons		
8		Roger C Zaklukiewicz		
8		Edward C Stein	Affirmative	
8	JDRJC Associates	Jim Cyrulewski		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Transmission Strategies, LLC	Bernie M Pasternack	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Negative	
9	New York State Department of Public Service	Thomas G. Dvorsky	Negative	
10	Midwest Reliability Organization	William S Smith	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito		
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Individual or group. (61 Responses)
Name (42 Responses)
Organization (42 Responses)
Group Name (19 Responses)
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Question 1 (48 Responses)
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Question 4 Comments (51 Responses)
Question 5 (0 Responses)
Question 5 Comments (51 Responses)

Group
TVA Transmission Reliability Engineering and Controls
Tim Ponseti, VP
Yes
TVA agrees with the general text; however, TVA believes that the 75 MW limit is too low. TVA believes that a better limit would be 100 MW - which is the amount for load shedding required to be reported under OE-417 under emergency operational policy. This would allow some future load growth as well as any possible new loads that may develop quickly in which a utility may not have time to complete necessary projects in a corrective action plan.
No
TVA recommends that up to 25 MW of planned interruption be allowed without triggering the need for a stakeholder process. Since the average use given in the survey was 19 MW and there is no evidence of harm to the BES reliability resulting from that use, there is no reason to require a stakeholder process for amounts less than 25 MW. This is consistent with the value cited in Section III.
No
TVA would like to propose that this Stakeholder process be postponed in the event that a transmission fix for a load drop issue was already planned within the next 2 or 3 years. Thus the stakeholder process would only occur for projects that had no fix planned within the next couple of years. TVA is also not sure how to satisfactorily address “health, safety, and welfare of the community” - TVA would appreciate some guidance on how to properly address this. TVA believes that item 1.b of Section II could contain CEII information and should have limited distribution. The appropriate non-disclosure agreements would need to be developed to prevent widespread publication of the information.
No
TVA believes that the requirements of 25 MW as well as any Bulk contingency over 300-kV is much too burdensome. TVA believes that only larger load drops (such as 50 MW and above) should require ERO review.
Please see responses to question #2,3, and 4. TVA believes that only load drops of higher magnitudes go thru the Stakeholder and regulatory review.
Group
Northeast Power Coordinating Council
Guy Zito
No
The 75MW of Firm Demand interruption is retail load that is being dropped. Dropping load in the general sense should not be endorsed, but it is recogn ized that there are special situations where it cannot be avoided. If a regulator responsible for retail load is comfortable with greater than 75MW being dropped in a rare situation, there should not be a requirement to build out of the situation. Provided there is no widespread, adverse effect on the reliability of the interconnected BES, the effect of a firm demand interruption on customers is under the purview of the applicable regulatory authority that is responsible for local transmission and retail service over the load to be curtailed. There is no technical basis for the 75MW figure. It was included as a result of a Section 1600 Data Request, and is an arbitrary value. There should not be a limit without a technically supportable reliability based reason.
There are no limits on non-consequential load loss for Single Contingency P2-2 and P2-3 (HV only), multiple

Contingencies P4 and P5 (HV only), and P6 and P7. Footnote 12 allows limited non-consequential load loss for single contingency P1, Multiple Contingency P3. Non-consequential load loss is not allowed for P2-2 and P2-3 (EHV), and P4 and P5 (EHV). Considering the EHV Facilities, it is not reasonable to accept some non-consequential load loss for single contingency P1 and P2-3, and then deny it for Multiple Contingency categories P4 and P5 which are statistically less frequent than the former. Also, the Multiple Contingency P7 (for which there is no limit on non-consequential load loss) is more frequent than P2-3, P4 and P5. This technical irregularity must be reviewed and addressed.
Individual
Thad Ness
American Electric Power
Yes
Yes
Yes
Yes
Group
Southwest Power Pool Reliability Standards Development Team
Jonathan Hayes
Yes
Yes
Yes
In this section the reference to Customers should only be Customers of Transmission and not open ended for any customer. Once it is sold wholesale the TP wouldn’t know where it is being sent to. We would also note that under some jurisdictions that there is a minimum duration threshold for keeping historical data on some of these events that are being requested under this section. Need to add language to accommodate these thresholds so as not to contradict what is being asked for by the regulatory bodies.
No
Section III is superfluous if the regulatory bodies are attending the open stakeholder process. This section should be removed due to the fact that if there is an issue or question on these events they should be addressed in the open stakeholder meeting. Not sure why the team decided to add the ERO as an entity to check after the regulatory body has approved the use. We feel like if there needs to bee coordination between affected entities that they could participate in the open stakeholder process as well. You could add that they include possible affected entities to the invite list of the open meeting to discuss these footnote applications under section 1.
Individual
Kenn Backholm
Public Utility District No.1 of Snohomish County
No
We believe the survey significantly underestimated the use of Non-Consequential Load Shedding because the survey asked about past usage of footnote b under Version 001, not about planned load shedding in TPL version 002 or the proposed footnote 12. TPL version 002 added several new contingencies, and also changed the Non Consequential Load shedding applicability for several contingencies. We have 4 specific concerns, followed by several suggested edits: 1) Analyzing the contingencies “P1.4 Loss of a Shunt Device” and “P2.1 Opening of a line section w/o a fault” are new requirements that will lead to increased use of footnote 12. It is common on fringes of the interconnected system to have weak sources. Significant utility investment will be redirected to remediate these fringe performance issues due to the P2.1 and its associated restrictions for firm load shedding and no RAS or UVLS mitigation. This is a low probability and low impact to the main grid contingency with a high mitigation cost, given the new mitigation restrictions. 2) Contingencies “P2.2 Bus Section fault” and “P2.3 Internal Breaker Fault” were previously defined as category “C multiple contingencies” with the restriction that the Firm Load shedding must be planned/controlled. However Version 002 no longer allows dropping nonconsequential load for EHV but removes all restrictions for HV load shedding. Since these contingencies result in opening the same breakers as category P1 contingencies, the use of footnote 12 should be consistent with P1. 3) Contingencies P3.1-P3.4 were previously defined as category “C multiple contingencies” with Firm loading shedding allowed. In version

2, these contingencies have been changed from allowing planned load shedding to only allowing Non-Consequential load shedding per footnote 12. Although this does not directly impact our utility, the survey results do not include utilities using "must-run" generation. 4) As demonstrated by multiple questions at the last webinar, many utilities do not understand the definition of Non-Consequential Loads, and therefore may not have correctly reported the usage of Non-Consequential Load Shedding. The v2 changes cascade to the unfortunate conclusion that UVLS and RAS are no longer permitted as cost effective transmission performance mitigation, despite new low probability contingencies that drive performance problems at the edges of the network. -Proposed changes: A) Change the maximum amount from 75 MW to 300 MW. Several other standards including CIP have a strong technical basis for selecting 300 MW as the maximum limit for load shedding programs. B) Footnote 12 on contingency 2.1 should be replaced with a new footnote 15 that reads " 15. For this contingency, load which is served radial from a remaining single source line may be shed as if it were Consequential Load." This change would acknowledge that while P2.1 does involve just one element, the likelihood of occurrence is similar to bus section faults, so the resulting system performance requirements should be similar. C) The first two sentences of footnote 12 should be deleted. Remove the first sentence because it is general in nature and is a basic tenant of any load-serving utility. Remove the second sentence because column 7 of Table 1 explicitly states where Non-Consequential Load Loss is allowed. D) The third sentence of footnote 12 should have the words "under footnote 12" added. Without this addition, all Non Consequential Load Loss including the allowed loss for P4, P5 and P6 would still be subject to Appendix 1. The revised sentence would read "When Non-Consequential Load Loss is used under footnote 12 within the Near-Term …"
No
In the first sentence, remove the words "as an element of a Corrective Action Plan." There are cases on the fringes of the system where Non-Consequential Load Loss is the preferred alternative in both the long term and short term, not as a temporary patch. Requiring the stakeholder process as part of Corrective Action Plan implies that using footnote 12 cannot be the long term choice. Since a Corrective Action Plan is a "list of actions and an associated timetable for implementation to remedy a specific problem," using this term removes the stakeholders ability to evaluated the costs and benefits and instead requires them to treat this a problem where the only solution is building new facilities.
No
We suggest removing section 2b "Assessment…health, safety…" for three reasons: 1)All outages have a negative impact on the community. Outages under footnote 12 do not inherently have more significant impact per MWhr lost than other outages allowed per Table 1. By requiring additional analysis for a similar societal impact, this provision discriminates against utilities at the fringes of the system. 2) While reminding planners to consider that their decisions do have real impacts to real people is a laudable goal, including this provision opens the door to significant legal liability and regulatory uncertainty. 3) An appendix to a footnote is the wrong place to introduce such a significant requirement. The Adequate Level of Reliability Task Force would be a more appropriate venue for this idea.
No
1) Similar to our comment on question 2, please remove the words "as an element of a Corrective Action Plan" from the first sentence. There are cases on the fringes of the system where Non-Consequential Load Loss is the preferred alternative in both the long term and short term, not as a temporary patch. Since a Corrective Action Plan is a "list of actions and an associated timetable for implementation to remedy a specific problem," using this term removes the stakeholders ability to evaluate the costs and benefits and instead requires them to treat this a problem where the only solution is building new facilities. 2) For any specific use of footnote b, there could be several applicable regulatory authorities such as small municipalities or public utility districts. The standard should clarify whether the planner must show evidence that every authority did not object, or whether the planner only needs to show that less that 25 MW was not rejected by the regulatory authorities. To accomplish this clarification, we propose: A) In Section III paragraph 1 and paragraph 5 change "regulatory authority or governing body" to "regulatory authorities or governing bodies." B) Add a sentence to bullet 2 to read "If multiple regulatory authorities or governing bodies are responsible for retail electric service issues, only the portion of Non-Consequential Load Loss exceeding 25 MW is subject to section III."
Public Utility District No.1 of Snohomish County generally disagrees with the October 2012 revision of TPL Table 1 Steady State & Stability Performance Footnotes (Planning Events and Extreme Events). "Footnote b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW." "Footnote 12. An objective of the planning process is to minimize the likelihood

and magnitude of Non-Consequential Load Loss following Contingency events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed ‘75’ MW.” The proposed revisions require that a Transmission Planner or Planning Coordinator provide assurance that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the interruptions of firm demand under TPL-002 footnote ‘b’ or TPL-001 footnote ‘12’ if the voltage level of the contingency is greater than 300 kV with certain sub-conditions or if the planned interruption of firm demand under these footnotes is greater than 25 MVA. In addition, under no case can planned Non-Consequential Load Loss exceed 75 MW. The magnitude and duration of load loss is a Level of Service (“LOS”) or Customer Service issue that is the jurisdiction of Public Utility Commissions and Local Electric Utility and Municipality boards. The boards and commissions represent their customers which often have diverse service and rate expectations that often are a result of local industry requirements, geography, urban/rural characteristics, and other factors of the particular service territory. Boards and commissions hold public meetings seeking input on various utility matters that often address services and rates. The rate impacts for customers are important; often more important than the service levels depending on the particular customer or customer class. Local boards and commissions are very close to these issues and weigh the input provided through public testimony to best represent their customer needs over the region they represent and have jurisdiction under state and local codes to address. The 75 MW Non-Consequential Load Loss threshold and the required NERC process do not resolve or address a reliability issue. The TPL footnotes address service requirements and should not be part of a NERC Reliability Standard any more than mandating specific System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI"). The Non-Consequential Load Loss requirement is an economic driven threshold that is not consistent throughout North America due to diverse customer needs and expectations. For instance, in some areas it may make economic sense and receive local approval to fund a $100 million system reinforcement to mitigate 1 in 20 year (5 percent chance of occurring) 76 MW Non-Consequential Load Loss exposure. However there are many communities that could not justify or support multi-million facilities to mitigate a 1 in 20 year event that may cause the Non-Consequential Load Loss of 76 MW of load. Public Utility District No.1 of Snohomish County supports removing the Non-Consequential Load Loss thresholds from the TPL Reliability Standards and allow the local boards and commissions to continue to address Customer Service Level issues as they are closest to the customers’ needs and have jurisdiction over this issue.
Group
MRO NSRF
WILL SMITH
No
(1) Change the wording at the end of the first sentence from “following Contingency events” to “following Contingency events and Contingency events during the planned (maintenance) outage of any bulk electric equipment)”. This would remind Transmission Planners and Planning Coordinators to include the consideration of planned outages at demand levels for which the outage would be performed. (2) Raise the maximum load dropping threshold for the footnote from 75 MW to 100 MW. A 100 MW threshold is reasonable because the DOE uses the intentional dropping of more than 100 MW as one of the thresholds for determininge when enough load is dropped to justify a formal system event analysis. (3) Add a sentence at the end of the footnote to read, “This footnote does not apply to any load that is not NERC registered (e.g. load that does not meet the greater than 25 MW NERC registration criterion). (4) If a portion of the non-consequential load loss used to mitigate a contingency is controllable by a demand side load management system, can it be excluded from the “Firm Demand interruption” in TPL-002-1c Table I footnote ‘b’ and/or ”Non-Consequential Load Loss” in TPL-001-2a Table 1 footnote 12? Does it have to be curtailed on a pre-contingent basis in order to be excluded from the non-consequential load total, or can it be excluded even if the curtailment happens through action of the UVLS? Does this load count towards the 25 MW and 75 MW thresholds? RECOMMENDATION: When describing “interruption of firm demand” or “non-consequential load loss” in footnote ‘b’ add the language “not counting load shed on a pre-contingent basis”. This would be added to the last sentence of footnote ‘b’ if it indeed should not be counted towards the 75 MW threshold. Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion. (5) If multiple companies own portions of the non-consequential load loss a used to mitigate a contingency at a single substation does each company’s load portion count towards the 25 MW and 75 MW thresholds or does the total load at the substation count? For example, 100% of the load at a substation is set to trip with automatic UVLS. Company A, B, and C own load amounts X, Y, and Z at the substation. Is the amount of load counted towards the 25 MW and 75 MW thresholds X+Y+Z, or is each counted separately? RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote ‘b’ could read “In no case can the planned Firm Demand interruption from under footnote ‘b’ exceed 75 MW from one entity.” Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion.

Yes
(1) In Attachment 1 Section I, what is the definition of a “stakeholder”? Which NERC functional entities would be included (TO, TOP, LSE)? Are the public residential and/or business owners that are affected included in the definition? Some parties may assume that local government representatives or residential or business owners are included as stakeholders. We believe it is most appropriate for the Transmission Owners, Transmission Operators, and Load-Serving Entities to objectively evaluate the risks of load shedding in a local area against the cost impact of a large transmission project on the rate base. RECOMMENDATION: Define stakeholder to be “affected Transmission Owners, Transmission Operators, and Load-Serving Entities.” (2) In Attachment 1 Section I item 1, what does “including applicable regulatory authorities” refer to? Is this the same body that “applicable regulatory authority or governing body” refers to in Section III? Are these requirements still applicable if the 25 MW threshold in Section III is not passed? RECOMMENDATION: Attachment 1 Section I Item 1 could read “… including applicable regulatory authorities or governing bodies responsible for retail electric service issues as described in Section III. A less vague statement allows the important parties to be included in every instance Attachment 1 is used.
No
Remove Item 2b because it requires the assessment of the footnote application impact on the potential health, safety, and welfare of the community. These types of assessments should be eliminated because they are not electric system reliability matters and were not stipulated by FERC.
No
(1) In Attachment 1 Section III, what is the definition of “applicable regulatory authority or governing body”? Is this the state PSC or PUC? Is it the Regional Reliability Organization (RRO)? Is it the Reliability Coordinator (RC)? RECOMMENDATION: Depending on the answer to the above question, define “applicable regulatory authority or governing body” more precisely. The language could read “applicable regulatory authority or governing body responsible for retail electric service such as the state Public Services Commission or Public Utilities Commission”. A less vague statement allows the important parties to be included in every instance Attachment 1 is used. (2) In Attachment 1, if non-consequential load loss is planned at multiple bulk delivery points to mitigate the same contingency should the total load loss count towards the 25 MW and 75 MW thresholds or should the loads be counted individually? EXAMPLE: There are two load serving substations (X load at substation B and Y load at substation C) on a long 115 kV line with 230/115 kV transformation at each end (substation A and substation D). Automatic under-voltage load shedding is in place at substations B and C, the UVLS relays at each substation making load trip decisions based on local voltage (i.e. independent operation). If one end of the 115 kV line trips and 115 kV voltage is below allowable levels at both substations X and Y, then the total load tripped by UVLS will be X+Y. Does the X+Y value count towards the 25 MW and 75 MW thresholds or are X and Y counted separately? What if X load is dropped for one contingency and Y load is dropped for a different contingency, is the total load counted X+Y or each load separately? RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote ‘b’ could read “In no case can the planned Firm Demand interruption under footnote ‘b’ exceed 75 MW for any single contingency.” Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion. (3) If non-consequential load loss is planned at multiple bulk delivery points in close proximity to mitigate different contingencies should the total load loss count towards the 25 MW and 75 MW thresholds or should the loads be compared individually? For example, there are two load serving substations (X load at substation B and Y load at substation C) on a networked 115 kV line with 230/115 kV transformation at both ends (substation A and substation D). Automatic under-voltage load shedding is in place at substations B and C that would trip X amount of load if one end of the 115 kV line tripped and 115 kV voltage was below allowable levels, and would trip Y amount of load if the other end of the 115 kV line tripped and 115 kV voltage was below allowable levels. Does the X+Y value count towards the 25 MW and 75 MW thresholds or are X and Y counted separately? In addition to the aforementioned contingencies, if the 115 kV line between substations B and C opens, both loads X and Y will trip. Now does the X+Y value count towards the 25 MW and 75 MW thresholds? (4) In Attachment 1, if UVLS relaying is programmed at a sub to trip the load in stages at multiple voltage setpoints, such that only a fraction of the load is tripped for a given contingency, is the entirety of the load still counted towards the 25 MW and 75 MW thresholds? EXAMPLE: Substation B has X load that will trip if the BES voltage gets to 0.92 p.u. and Y that will trip if the BES voltage gets to 0.88 p.u. If only X amount of load is required to mitigate a single contingency in the near-term TPL assessment, is X load counted towards the 25 MW and 75 MW thresholds or is X+Y load counted? Is there a difference if the Y load is at a different, nearby substation with both loads having the aforementioned tripping logic? RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote ‘b’ could read “In no case can the planned Firm Demand interruption under footnote ‘b’ (as demonstrated in the near-term horizon analysis) exceed 75 MW.” Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion
1. In TPL-002-1c Table I and TPL-001-2a Table 1 can “Firm Demand interruption” or “Non-Consequential Load Loss” be initiated by a manual event such as operator action or does it need to be automatic? RECOMMENDATION: In TPL-002-1c Table I footnote ‘b’ add a sentence stating “Acceptable methods to enact Firm Demand Interruption may include manual or automatic processes that can be initiated within a reasonable timeframe”
Group
Arizona Public Service Company

Janet Smith
No
The 75 MW threshold is too low. No technical justification has been given for choosing 75 MW. It should be a significantly higher value for TPL-002. Currently AZPS does not use non-consequential load dropping to meet any standard but this option should be preserved. There could be times when alternate to the load dropping would be building a new transmission line costing hundreds of millions of dollar for a very low probability scenario of high load conditions. The threshold value should be 100 MW or more.
Yes
No
Item 2b: Reference to health, safety, and welfare is unnecessary. All demand interruption are going to have some impact on health, safety, and welfare. The impact is subjective and will simply result in unnecessary study reports by consultants and will act as a road block.
No
The threshold of 25 MW in item 2 of section III is too low. It should be same as the maximum allowed value in foot note b. In addition, AZPS does not agree that no objection assurance by the Regional Entity should be required. Once the process has been fully vetted by the stakeholders, including the regulatory authority for retail service, there is absolutely no need for Regional Entity involvement. There would be no adverse affect of non-consequential load tripping on the BES. Hence no reason for Regional Entity involvement is needed.
The following comment relates to Table 1. It is not clear why footnote 12 applies only to P2-1. The events P2-2, P2-3, P4, P5 are much less probable and the footnote 12 should be applicable to all these events. Why is that loss of non-consequential load is allowed for line tripping without fault but not for a bus fault which is much less likely and could result into same line trip. Similar arguments apply to other scenarios listed above.
Individual
Travis Metcalfe
Tacoma Power
No
We believe the survey significantly underestimated the use of Non-Consequential Load Shedding because the survey asked about past usage of footnote b under Version 001, not about planned load shedding in TPL version 002 or the proposed footnote 12. TPL version 002 added several new contingencies, and also changed the Non Consequential Load shedding applicability for several contingencies. We have 4 specific concerns, followed by several suggested edits: 1) Analyzing the contingencies “P1.4 Loss of a Shunt Device” and “P2.1 Opening of a line section w/o a fault” are new requirements that will lead to increased use of footnote 12. It is common on fringes of the interconnected system to have weak sources. Significant utility investment will be redirected to remediate these fringe performance issues due to the P2.1 and its associated restrictions for firm load shedding and no RAS or UVLS mitigation. This is a low probability and low impact to the main grid contingency with a high mitigation cost, given the new mitigation restrictions. 2) Contingencies “P2.2 Bus Section fault” and “P2.3 Internal Breaker Fault” were previously defined as category “C multiple contingencies” with the restriction that the Firm Load shedding must be planned/controlled. However Version 002 no longer allows dropping nonconsequential load for EHV but removes all restrictions for HV load shedding. Since these contingencies result in opening the same breakers as category P1 contingencies, the use of footnote 12 should be consistent with P1. 3) Contingencies P3.1-P3.4 were previously defined as category “C multiple contingencies” with Firm loading shedding allowed. In version 2, these contingencies have been changed from allowing planned load shedding to only allowing Non-Consequential load shedding per footnote 12. Although this does not directly impact our utility, the survey results do not include utilities using “must-run” generation. 4) As demonstrated by multiple questions at the last webinar, many utilities do not understand the definition of Non-Consequential Loads, and therefore may not have correctly reported the usage of Non-Consequential Load Shedding. The v2 changes cascade to the unfortunate conclusion that UVLS and RAS are no longer permitted as cost effective transmission performance mitigation, despite new low probability contingencies that drive performance problems at the edges of the network. -Proposed changes: A) Change the maximum amount from 75 MW to 300 MW. Several other standards including CIP have a strong technical basis for selecting 300 MW as the maximum limit for load shedding programs. B) Footnote 12 on contingency 2.1 should be replaced with a new footnote 15 that reads “ 15. For this contingency, load which is served radial from a remaining single source line may be shed as if it were Consequential Load.” This change would acknowledge that while P2.1 does involve just one element, the likelihood of occurrence is similar to bus section faults, so the resulting system performance requirements should be similar. C) The first two sentences of footnote 12 should be deleted. Remove the first sentence because it is general in nature and is a basic tenant of any load-serving utility. Remove the second sentence because column 7 of Table 1 explicitly states where Non-Consequential Load Loss is allowed. D) The third sentence of footnote 12 should have the words “under footnote 12” added. Without this addition, all Non Consequential Load Loss including the allowed loss for P4, P5 and P6 would still be subject to Appendix 1. The revised sentence would read “When Non-Consequential Load Loss is used under footnote 12 within the Near-Term …”
No

In the first sentence, remove the words "as an element of a Corrective Action Plan." There are cases on the fringes of the system where Non-Consequential Load Loss is the preferred alternative in both the long term and short term, not as a temporary patch. Requiring the stakeholder process as part of Corrective Action Plan implies that using footnote 12 cannot be the long term choice. Since a Corrective Action Plan is a "list of actions and an associated timetable for implementation to remedy a specific problem," using this term removes the stakeholders ability to evaluated the costs and benefits and instead requires them to treat this a problem where the only solution is building new facilities.
No
We suggest removing section 2b "Assessment…health, safety…" for three reasons: 1)All outages have a negative impact on the community. Outages under footnote 12 do not inherently have more significant impact per MWhr lost than other outages allowed per Table 1. By requiring additional analysis for a similar societal impact, this provision discriminates against utilities at the fringes of the system. 2) While reminding planners to consider that their decisions do have real impacts to real people is a laudable goal, including this provision opens the door to significant legal liability and regulatory uncertainty. 3) An appendix to a footnote is the wrong place to introduce such a significant requirement. The Adequate Level of Reliability Task Force would be a more appropriate venue for this idea.
No
1) Similar to our comment on question 2, please remove the words "as an element of a Corrective Action Plan" from the first sentence. There are cases on the fringes of the system where Non-Consequential Load Loss is the preferred alternative in both the long term and short term, not as a temporary patch. Since a Corrective Action Plan is a "list of actions and an associated timetable for implementation to remedy a specific problem," using this term removes the stakeholders ability to evaluate the costs and benefits and instead requires them to treat this a problem where the only solution is building new facilities. 2) For any specific use of footnote b, there could be several applicable regulatory authorities such as small municipalities or public utility districts. The standard should clarify whether the planner must show evidence that every authority did not object, or whether the planner only needs to show that less that 25 MW was not rejected by the regulatory authorities. To accomplish this clarification, we propose: A) In Section III paragraph 1 and paragraph 5 change "regulatory authority or governing body" to "regulatory authorities or governing bodies." B) Add a sentence to bullet 2 to read "If multiple regulatory authorities or governing bodies are responsible for retail electric service issues, only the portion of Non-Consequential Load Loss exceeding 25 MW is subject to section III."
Individual
Steven R. Wallace
Seminole Electric Cooperative, Inc.
Yes
No
#1. It is unclear what factors must be met in order to be an affected stakeholder under the Stakeholder Process in Attachment 1? This process appears to be devoid of any objective factors that can assist an entity in determining whether a party is a stakeholder or not. NERC should define what an "affected stakeholder" is or list factors to assist industry in making such a determination. #2. In Standard TPL-002-1c, Attachment 1, Section I. "Stakeholder Process," there was a section added at the end of this subsection that is three lines in length. This section states that a stakeholder process does not need to be repeated unless there has been a "material change." It is clear from the latest webinar presentation on this Project that this language is not "clear and unambiguous". NERC does not present any metrics, whether qualitative or quantitative, to guide industry as to when a material change occurs to an application of footnote 'b.' Without any metrics to guide industry, it is bewildering that NERC reasons that entities will consistently interpret what a material change constitutes. Therefore, SECI believes that this provision is in conflict with the NERC Rules of Procedure and FERC Order 762. #3. In Standard TPL-002-1c, Attachment 1, Section I. "Stakeholder Process," the requirement that the process "shall be documented" was deleted from the first paragraph. It does not appear to be reasonable that a process that is not written, nor known to any stakeholder, meets the common understanding of "open and transparent." Seminole believes that the requirement that the process be documented and that documents be available to potential affected parties be reinstated into the Standard.
Yes
Yes
Individual
Nazra Gladu
Manitoba Hydro

No
Given that it is deemed that a stakeholder procress is required, there is no rationale for a maximum level. The stakeholders are in the best position to judge the appropriate level of allowable curtailment.
No
A stakeholder process should not be required in jurisdictions where a legislation already authorizes interruptions, as consent of stakeholders cannot override legislation.
No
The word 'assure' should be 'ensure' in the opening paragraph of III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required.
(1) Effective Date section 5: The language used in the revision that was made is fine, however, where the language has been placed in the section is confusing. The language has been added to the end of the sentence that starts 'in those jurisdictions where regulatory approval is not required' and lumped those two concepts together. In our mind, there should be 3 separate concepts 1) where regulatory approval required 2) where regulatory approval not required and 3) as may otherwise be approved by applicable laws. (2) Corresponding changes do not appear to have been made, TPL 1 and TPL 2 are not consistent in terms of the language used in the Effective Date section or the Attachment 1 (the sections to which changes were made since last circulation).
Individual
James Tucker
Deseret Generation & Transmission
No
The limitation of Non-Consequential load loss to the 25 MW-75 MW level with a hard limit at 75 MW is arbitrary and give no deference to the cost of the cure. In the West the high cost of a fix may not be in the public interest. The 75 MW hard high limit should be replaced with a soft 75 MW limit but allowing higher levels if the governing body or regulatory authority approves it.
Yes
Yes
Yes
Individual
Melissa Kurtz
USACE
Individual
Chris Pink
Tri-State Generation & Transmission Association
No
No
NERC Functional Model definitions for Planning Authorities and Transmission Planners do not include the types of activities being proposed in "Attachment 1." How is it appropriate to mandate to functional entities functions that are outside those defined in the NERC functional model?
No
In the NERC Glossary of Terms, Interruptible Demand is defined as "Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment." The process described in Attachment 1 creates an agreement between stakeholders (aka "end-use customers") and their transmission providers. Thus, if the process described in Attachment 1 is followed, the "Firm Demand" referenced would be reclassified as "Interruptible Demand." In essence, "Footnote b" does not allow the interruption of Firm Demand. It merely requires that if interruption of Demand is required, it can only be Interruptible Demand. If this was the intention of FERC, NERC, and the Drafting Team, why didn't the drafting team just state "Interruption of Firm Demand is not allowed"?
No
How would section III of "Attachment 1" be applied to entities that only deliver wholesale electric service and no retail electric service?
It is not clear how transmission projects with long lead times (such as T-lines) would be handled by "Footnote b". Is it the drafting team's intent to make it acceptable for a TP to plan for shedding Firm Demand in the Near Term

Planning Horizon without meeting the conditions shown in “Attachment 1” when a mitigating project is planned that cannot be constructed in the Near Term Planning Horizon?
Individual
Andrew Z. Pusztai
American Transmission Company
No
ATC recommends the following alternative language for both Footnote ‘b’ (Table 1 in TPL-002-1c [page 6]) and Footnote ‘12’ (Table 1 in TPL-001-2a [page 14]: (1) Change the wording at the end of the first sentence from “following Contingency events” to “following Contingency events for the prior condition of all equipment in service or during the planned (maintenance) outage of any bulk electric system equipment”. This would remind Transmission Planners and Planning Coordinators to include the consideration of planned outages at demand levels for which the outage would be performed. (2) In the last sentence of the footnote, raise the maximum load dropping threshold for the footnote from 75 MW to 100 MW. A 100 MW threshold is reasonable because the DOE uses the intentional dropping of more than 100 MW as one of the thresholds for determining when enough load is dropped to justify a formal system event analysis. (3) Add a sentence at the end of the footnote to read, “This footnote does not apply to any load that is not NERC registered (e.g. load that does not meet the greater than 25 MW NERC registration criterion).
Yes
No
ATC recommends the following change in Section II of Attachment 1 applicable to both standards TPL-002-1c [page 8] and TLP-001-2a [page16]: Remove Item 2b altogether because it requires the assessment of the footnote application impact on the potential health, safety, and welfare of the community. These types of assessments should not be required in the Standards because they are not electric system reliability matters and were not stipulated within the FERC Order762.
Yes
Individual
John Collins
Platte River Power Authority
No
We do not support a maximum threshold. 1) It is not appropriate to enforce a one size fits all maximum value that might unnecessarily over-burden some communities. 2) The public process proposed in this standard provides significant transparency from the transmission utilities and opportunity for community input to decisions that will impact both the community's reliability and rates. 3) Leave the maximum capacity threshold decisions to local regulatory commissions and Boards of Directors.
Yes
Although these descriptive steps for a public process seem out of place in a reliability standard, Section 1 is in line with the planning principles of FERC Order 890.
Yes
No
See answer to Question 1.
Individual
Don Jones
Texas Reliability Entity
Yes
Attachment 1, section I (Stakeholder Process) should be clarified to specify which ‘responsible entity’ needs to utilize or develop a transparent stakeholder process. For example, if a contingency event in Entity A’s system causes Entity B to have to shed non-consequential firm load to meet the BES performance requirements, which Entity is responsible for ensuring the required review? TRE proposes adding the following sentence to the first paragraph to assign responsibility for this type of scenario: “The Planning Coordinator or Transmission Planner accountable for the contingency event will be responsible for implementing the stakeholder process and regulatory review.”
Yes

In Section II, part 1b, TRE suggests replacing 'applicable rating' with 'steady state performance requirments', to account for all the BES performance requirements (in particular, steady-state and post-contingency voltages) for which the footnote may be utilized.
Yes
1. TRE requests clarification whether the 25 MW limit of Non-consequential Load Loss (Section III (2)) applies to a single contingency event for a specific Transmission Planner's region or to the entire Planning Coordinator area. For example, if a single contingency requires multiple Transmisson Planners to shed load, is each Transmission Planner allowed to drop up to 25 MW of load before requiring regulatory review? Or did the SDT intend to require the Transmission Planners/Planning Coordinator to submit the plan for regulatory review if the total load shed for the single contingency equals or exceeds 25 MW? 2. TRE feels that the requirement in Section III that the Planning Coordinator or Transmission Planner must submit information to the ERO for a determination of whether there are "any Adverse Reliability Impacts" is overly burdensome to industry, assuming that this refers to the new definition of "Adverse Reliability Impact" (limited to Instability and Cascading). It is extremely unlikely that any such impacts will result from application of this footnote, and any that might occur will be identified in the stakeholder process. If the ERO determination step is retained, then a timeline should be included for completion of the ERO determination process.
Individual
Kirit Shah
Ameren
No
It appears that a least common denominator approach was used to develop the upper limit of 75 MW. Only 1 out of 18 respondents would drop 75 MW of load, and only two respondents would drop 61-70 MW of load. Our review of the data request responses concludes that only 22% of the respondents that presently utilize footnote "b" would drop more than 50 MW, and only 33% of the respondents that use footnote "b" would drop more than 40 MW. The proposed 75 MW limit is too high and is not supported by the responses to the data request. An upper limit of 40 MW is more appropriate, based on the data responses.
No
It is our opinion that that the stakeholder process should be conducted at least once every five years if non-consequential load is planned to be dropped as part of the Corrective Action Plan to meet single contingency events. If conditions have not materially changed since the last review, this information should still be communicated to the stakeholders.
Yes
We believe that item 1b of Section II would contain critical electric infrastructure information (CEII) and should have limited distribution. The appropriate non-disclosure agreements would need to be developed to prevent widespread publication of the material.
No
The responses to the data request indicate that 33% of the respondents that use footnote "b" would drop 20 MW or less for single contingency events. Based on the data, we believe that the threshold for reporting should be 20 MW instead of 25 MW. As noted above in the response to item 1, we also believe that an upper limit of 40 MW should be established, again based on the responses to the data request. We find this proposed stakeholder process unique because we are inviting retail regulatory authorities to become involved in the compliance process for a handful of utilities now, but potentially for more in the future. We are unaware of any other standards where a state governmental agency is needed to grant permission for utilities to utilize certain aspects of the standard. We believe that this proposed process would potentially set a bad precedent, is not good policy for either the regulators or the transmission planners, and does not belong in a NERC standard.
It might be helpful to probe further with the respondents who have no planned upgrades identified to address the dropping of non-consequential load to see what relevant system upgrades might entail, and the estimated costs associated with such upgrades, to address such situations.
Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
No
As an initial matter, ERCOT does not believe the planning process should allow for nonconsequential load shedding under single contingency conditions. Accordingly, ERCOT takes no position on the proposed maximum load shedding amount. Even though the NERC BoT approved the Stakeholder Process, ERCOT does not believe that the Stakeholder Process should be included as an Attachment to a footnote to a reliability standard. Also, there is an inconsistency in the terminology used in the footnotes relative to the load shed – firm demand and non-consequential load are both used. Non-consequential load is the correct term and the language should be consistent. Although it is ERCOT's position that non-consequential load should not be allowed to be shed under single contingency conditions from a planning perspective, if the SDT elects to retain a vehicle for such exceptions,

it should establish objective, reliability based criteria that lend themselves to inclusion in a reliability standard. This is consistent with the general approach for reliability standards, which prescribe the "what", not the "how". If the exceptions are based on objective criteria that are known upfront, and those criteria reflect appropriate reliability based technical justifications, then the risk of unwarranted exceptions to the general prohibition due to misuse of the exception process is mitigated. Furthermore, the exception process should be external to the NERC Reliability Standards (e.g. in the Rules of Procedure), which should merely reference authorized exceptions granted pursuant to that process. With respect to the stakeholder process, in no case should a reliability standard mandate a stakeholder process in any respect, procedural or substantive. In ISO/RTO regions, stakeholder processes fall within ISO/RTO governance matters. These issues are beyond the purview of NERC Reliability Standards. In other regions, although the relevant functional entities do not have stakeholder processes analogous to ISOs/RTOs, any relevant processes are similarly beyond the scope of the reliability standards. Accordingly, the SDT should eliminate all revisions related to the establishment of a stakeholder process. As discussed in response to question 5, FERC is not requiring this approach, but rather has only provided guidance with respect to ways to possibly bring the prior proposal in line with applicable regulatory approval standards for reliability standards. Additionally, as a general matter, substantive reliability standards requirements should not be imbedded within a footnote to a requirement. In this case, not only is there a substantive requirement imbedded in the footnote, there is also a substantial attachment (which must become part of the enforceable standard requirements}… and, to make it worse, the attachment is an attachment to the footnote, rather than an attachment to and referred to by a reliability standard requirement.
No
Please see ERCOT's response to Question 1 – stakeholder processes are not appropriate for NERC standards.
No
Please see ERCOT's response to question 1-the NERC Reliability Standards should not contain requirements related to stakeholder processes, whether they are procedural or substantive. If an exception process is retained, it should be outside of the NERC Reliability Standards (e.g. in the Rules of Procedure). To the extent the proposed standard inappropriately retains the stakeholder related aspects, ERCOT also provides the following comments on Section II-the ERCOT comments are in parentheses for easy reference and distinction relative to the proposed requirements. II. Information for Inclusion in Item #3 of the Stakeholder Process The responsible entity shall document the planned use of Firm Demand interruption under footnote 'b' which must include the following: (ERCOT COMMENT: This is all that is needed for this. The documentation would be relative to the objective criteria developed for this purpose.) 1. Conditions under which Firm Demand interruption under footnote 'b' would be necessary: a. System Load level and estimated annual hours of exposure at or above that Load level b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency (ERCOT COMMENT: "1" is not necessary if objective criteria are developed as benchmarks for the exception process. In that case, exceptions would only be allowed if the objective criteria were met, regardless of the underlying assumptions related to conditions and contingencies.) 2. Amount of Firm Demand MW to be interrupted with: a. The estimated number and type of customers affected b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community (ERCOT COMMENT: The considerations reflected in a and b are inappropriate for a reliability standard. Appropriate considerations for reliability standards are related to the reliability performance of the system. The considerations in a and b are more akin to quality of service issues better suited for regional policy discussions. It is not within the purview of the SDT to address those matters.) 3. Estimated frequency of Firm Demand interruption under footnote 'b' based on historical Performance (ERCOT COMMENT: Historical performance is irrelevant. If the SDT is going to retain revisions that accommodate non-consequential load shedding, then the only relevant metrics are the objective criteria that set the benchmarks for such exceptions.) 4. Expected duration of Firm Demand interruption under footnote 'b' based on historical performance (ERCOT COMMENT: See ERCOT response to "3" above.) 5. Future plans to mitigate the need for Firm Demand interruption under footnote 'b' (ERCOT COMMENT: This is redundant to the requirement in the reliability standards that requires a plan to resolve any violations identified in the planning process. Furthermore, if load shedding is allowed, this requirement doesn't make sense. Presumably the idea behind allowing these exceptions is to obviate the prospective need for other alternatives. If that is not the case, then there is no need to allow the exceptions, because the transmission upgrades to mitigate the need for load shedding can be established in the planning horizon.) 6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 'b' (ERCOT COMMENT: The basis for the load shedding exception is to provide a means to meet the TPL performance requirements in the context of a planning assessment. Accordingly, this is redundant to the planning assessments, the point of which is to identify and resolve performance issues.) 7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote 'b' (ERCOT COMMENT: Load shedding exceptions should be based on objective criteria and be reviewed pursuant to a process external to the NERC reliability standards. Alternative discussions could be part of that external process.) 8. Assessment of potential overlapping uses of footnote 'b' including overlaps with adjacent Transmission Planners and Planning Coordinators (ERCOT COMMENT: It is not clear what this means. Each functional entity performs assessments relative to its own system. This appears to introduce a vague regional transmission planning requirement with no structure or rules for such assessments.)
No
If non-consequential load shedding is allowed for single contingency conditions, as discussed above, it should be

based on objective critieria. As such, there is no need for the proposed stakeholder process, including the Section Ill instances requiring regulatory review. Furthermore, establishing approval roles in planning processes for entities other than the relevant functional entities conflicts with the appropriate roles, and appropriate separation of those roles, of the relevant entities (i.e. the planning authority and the state regulatory body and NERC RE). Typically a functional entity performs the functional activity, and others relevant to the proposed process in the standard perform compliance and regulatory oversight of the functional performance. This is a practical concern, and also potentially raises conflicts between governing authorities that create the separation of roles, where, typically, the relevant authorities establish a functional entity as the planning entity, and NERC and its REs and state regulators (as relevant – e.g. in ERCOT) are charged with compliance and regulatory oversight. As with the other stakeholder process sections, that section should be eliminated.
The SDT is not required to utilize the stakeholder approach by Order 762 or any other relevant FERC orders. FERC merely provided guidance as to how the rejected proposal could be improved. However, if the SDT elects to pursue an exception process, such exceptions should be based on objective criteria, and the process should be external to the NERC Reliability Standards (e.g. in the Rules of Procedure). In Order 693, FERC directed NERC to clarify footnote (b) to prohibit shedding firm load except for consequential load loss (Order 693 at PP 1773, 1794 and 1797}. In a related compliance order, FERC reaffirmed its position. (130 FERC 61,200 (March 18, 2010) at PP 8-10 (Compliance Order)) In a subsequent order, FERC clarified that its Order 693 directive did not preclude consideration of specific comments related to planning the system based on load shedding at the "fringes" of a system. (131 FERC 61,231 (June 11, 2010) at P 21 (Clarification Order)) FERC held that regional variances for case-specific circumstances or a case-specific exception process to plan for the loss of firm service "at the fringes of various systems" would be acceptable. (131 FERC 61,231 (June 11, 2010) at P 21 (Clarification Order)) However, FERC also stated that it viewed the basis for such exceptions as economic, not reliability, with the justification being that it was not economic to invest in the bulk electric system to serve all non-consequential load customers under some single contingency conditions. (Order 693 at P 1792) FERC made clear that any such regional differences or case specific exception processes cannot reflect the lowest common denominator, and, they must be technically justified, and such justification must be strong. (Clarification Order at P 21, See also Order 693 at P 1794) This is consistent with FERC's position that this is a matter of "fundamental issue of transmission service". (Order 693 at P 1793) In recognizing that meeting firm demand under single contingency conditions is fundamental to transmission service, FERC noted that NERC's definition of firm transmission service is the "highest quality (priority) service offered to customers ... that anticipates no planned interruption." (Order 693 at P 1793) Against this background, NERC filed revisions to footnote b that allowed transmission plans to shed non-consequential load under single contingency conditions, provided appropriate process applied to such planning determinations/outcomes. In Order No. 762, {139 FERC 11 61,060 (April 19, 2012)) FERC rejected the approach proposed by NERC and provided guidance on acceptable approaches to footnote b. However, FERC did not endorse or mandate any particular approach. Rather, it merely urged "NERC to develop in a timely manner an appropriate modification that is responsive to the Commission's directives in Order No. 693 and our concerns set forth in this Final Rule." (Order 762 at P21) FERC stated that in order for any such proposal to have merit, it must be technically justified and must not reflect the lowest common denominator. As discussed, the proposed stakeholder approach is not appropriate for NERC Reliability Standards. The SDT should abandon that approach and consider simple revisions to footnote b that reference a case by case exception process based on objective criteria that is external to the NERC Reliability Standards (e.g. Rules of Procedure). Alternatively, it should develop revisions to the continent-wide standards that clarify that non-consequential load shedding is not generally permitted for single contingency conditions, but, consistent with FERC's orders, exceptions could be established pursuant to regional rules based on the need/appropriateness in a particular region. Consistent with the above discussion, if the SDT elects to pursue revisions that accommodate shedding non-consequential load in transmission planning for single contingency conditions, it should abandon the stakeholder process approach. The establishment of exceptions is better suited for regional rules or pursuant to a process outside of the reliability standards - e.g. via the Rules of Procedure, because such a process is not suited for a continent-wide reliability standard. Regardless of whether the issue is addressed via an external process, or left to regional variances, this issue needs to be addressed in a relatively timely manner because the uncertainty is affecting planning processes.
Individual
David Kiguel
Hydro One Networks Inc.
No
We disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard. Provided there is no widespread, adverse effect on the reliability of the interconnected bulk electric system, the effect on customers of a firm demand interruption is the responsibility of the applicable regulatory authority or its delegated agencies responsible for local transmission and retail service over the load to be curtailed. If it is decided to proceed with the 75 MW or any other value, we propose replacing the sentence, in the footnote and in attachment one, section III that reads: "In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW." with "In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss under footnote 12 for a non-US Registered Entity should be determined by the applicable Regulatory Authority or Governmental Authority or its delegated agency in that is responsible for retail electric service issues in that jurisdiction."

No
The process presented in Section I is overly prescriptive. If a section that prescribes the principles of a stakeholder process is required, then for non-US entities this section should simply require that the process must be approved by the applicable Regulatory Authority or Governmental Authority or its delegated agency that is responsible for local transmission and retail service for the load to be curtailed in that jurisdiction.
No
The process presented in Section II is overly prescriptive. If a section that prescribes the information requirements for a stakeholder process is required, then for non-US entities this section should simply require that the process information requirements must be in accordance with the requirements of the applicable Regulatory Authority or Governmental Authority or its delegated agency that is responsible for local transmission and retail service in that jurisdiction.
No
The process presented in Section III is overly prescriptive and duplicates information not necessary for its intended purpose. As stated in Q1, we disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard, and propose alternate language in our response to Q1. If this section is required to address a review of the use of footnote 12 to ensure that there are no wide-spread adverse reliability impacts on the bulk power system, then it should be limited to the information required for that purpose. Provided there is local support for the use of Non-Consequential Load Loss under footnote 12, only information items 6 and 8 from section II are relevant for this assessment—the remainder are not required for this section and should be deleted. Items 1 and 2 complicate this section and are unneccesary. They should be replaced by a phrase such as "for those planning events where the use of footnote 12 is referenced." We disagree with the need to submit this information to the ERO for a determination of whether there are any Adverse Reliability impacts caused by the use of Non-Consequential Load Loss. This will introduce a new type of review at the ERO that will create uneccesary delays and burden, and is inconsistent with (and not required for) all of the other performance requirements in the TPL standards. Submitting the analysis to the adjacent Planning Coordinators and Tranmission Planners, and any functional entity that requests it, as called for in requirement R8 of TPL-001-2 should be sufficient.
(1) We'd like to reiterate our support for allowing load interruption for a single contingency with sufficient review/oversight and under acceptable conditions, including no adverse impact on the reliability of the bulk electric system. The reliability aspects (BES performance requirements) should be reviewed for acceptability by the adjacent Planning Coordinators and Transmission Planners. However, issues pertaining to economics or externalities which may not be directly reliability-related are always available for review and debate by the stakeholders via the regulatory processes and subject to approval by the regulatory authority of each jurisdiction (particularly those in Canada and Mexico). (2) Furthermore, we request that Table 1 of TPL-001-2a (previous TPL-001-2 approved by the NERC BOT) be corrected for EHV contingencies in P2, P4 and P5 categories to allow the application of footnote 12 that is allowed for the P1 events. If a load is allowed to be interrupted for a single EHV transmission line contingency (Category P1), it should be allowed to interrupt the same load if the primary breaker fails (the event becomes category P4) and the fault is cleared by other breakers. Similarly, if the same breaker has an internal fault or there is a fault on the same bus section (Category P2) or there is a failure of a relay (Category P5), which results in the loss of the same EHV transmission line, it should be allowed to interrupt the same load. Events in P2, P4, and P5 can involve more elements and can be more onerouse and stressful to the system than the P1 events, and if use of footnote 12 is permitted in the less stressful P1 events, it must also be permitted in P2, P4 and P5 events. This issue has been raised by many entities in previous occasions and we believe the STD has not provided a convincing response. (3) We suggest that NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve them. Accordingly, we believe that the focus of foot note 'b', and footnote 12 should be that interruption of load must not have a widespread, adverse impact on the reliability of the interconnected BES. A continent-wide reliability standard should not concern itself with the reliability of supply or supply continuity for local load, as that is the responsibility of the applicable regulatory authority or its agencies responsible for local transmission and retail service over the load to be curtailed. If NERC and/or FERC believe that MW threshold needs to be addressed within NERC Standard for US registered entities then the standard must clearly state that the requirement is for US registered entities only.
Group
Seattle City Light
paul haase
Individual
Martyn Turner
LCRA Transmission Service Corporation
No
No
No

No
LCRA TSC disagrees with the October 2012 revision of TPL Table 1 Steady State & Stability Performance Footnotes (TPL-002-1c, footnote 'b' and TPL-001-2a footnote 12). The proposed stakeholder process required to be conducted during each Planning Assessment is overly burdensome. Further, it is not clear from the proposed process that a key concern expressed by the Commission with respect to use of Firm Demand load shedding is addressed - Notice to Firm Demand Customers. In addition, the proposed stakeholder process introduces several questions that need to be further clarified. For example: 1) Who defines the processes and procedures to be used? 2) Who is/are the decision maker(s)? 3) Who determines if the processes and procedures were followed? 4) Who carries out the administrative tasks (such as notice, securing meeting space,….)? 5) Who can participate? Does someone need to demonstrate a material interest in order to participate? 6) What are the means of participation (accepted forms of communication, timelines…)? 7) What are the criteria for decision-making? 8) What is the process for dispute resolution? How would does an Attachment become part of a NERC Standard? Should Attachment 1 be a requirement? In addition, support is needed for the bright-line 25 MW level. Lastly, the statement, "Before a Firm Demand interruption under footnote 'b' is allowed to be utilized as an element of a Corrective Action Plan in Year One of the Planning Assessment," implies that Firm Demand interruption may be used for years two through five of the Planning Assessment without the stakeholder process.
Group
Duke Energy
Greg Rowland
No
Regarding the maximum capacity item, we believe that 75 MW is much too low. While Duke Energy has not historically used the footnote, setting the upper limit at 75 MW raises a concern. An upper limit of 75 MW severely limits the ability of a Transmission Planner to use the footnote. The 75 MW limit appears to be the maximum reported in the survey. The survey is a snapshot in time and to assume that there never have been nor never will be situations where the correct decision of a Transmission Planner and its stakeholders would be to exceed the 75 MW limit is illogical. The 75 MW limit is likely to create a situation where a Transmission Planner is forced to convert a network line to radial in order to remain in compliance with the standard, to the detriment of reliability to customers. The key to understanding use of the footnote is realizing that, in most cases, using the footnote is extremely unlikely to result in customer outages, because the probablility of the initiating contingency occurring under conditions requiring additional load shed is very low. A more reasonable upper limit would be the 300 MW limit that is established as the threshold for DOE Disturbance Reporting. It is also important to remember that no matter what upper limit is established, Non-consequential Load Loss of 25 MW or greater cannot be included in Year One of the Planning Assessment if the applicable regulatory authority or governing body responsible for retail electric service issues objects.
Yes
Yes
Yes
Individual
Joe Tarantino
Sacramento Municipal Utility District
No
There is no reliability benefit with an establish MW threshold. Implementing any threshold is descriptive and the standard should depict an outcome not the means of the outcome.
1) The decision of necessary infrastructure addition versus a determination of load shed in lieu of costly transmission should be determined at the Public Utility Commission or Local Board of Directors not through a laod level limitation. 2) There are no impacts to the BES for load shedding actions where it is determined that it is confined to a set boundaryand demonstrate to not lead to cascading, uncrontrolled separation or blackout. 3) Where a concern that a stakeholder process be "gamed" to allow the unscrupulous entity to claim notification of affected stakeholders was followed should not dictate a continent-wide standard direction for other stakeholders.
Individual

Patricia Robertson
BC Hydro and Power Authority
BC Hydro appreciates the efforts of the SDT in revising standards TPL-002-1c – System Performance Following Loss of a Single BES Element (footnote b) and TPL-001-2a – Transmission System Planning Performance Requirements (footnote 12). BC Hydro votes YES in support of this ballot and wishes to provide the following two comments: 1.At this time BC Hydro has concerns about the level of stakeholder consultation that might be required as a result of the implementation of this standard and will bring this concern to the attention of our regulator if necessary. 2.At this time BC Hydro has concerns about the instances for which regulatory review of non-consequential load loss under footnote 12 is required and will discuss those with our regulator if necessary.
Group
Bonneville Power Administration
Chris Higgins
Yes
Yes
No
BPA does not support including information under Section II.2.b, an assessment of the use of Non-Consequential Load Loss on the health, safety, and welfare of the community. It would be nearly impossible for a planner to predict this in a future case since it is hard to predict what loads will actually materialize in the future. In addition, this information does not support reliability of the BES since reliability of the transmission system is assessed by meeting required technical performance for certain contingencies and under certain conditions.
No
For use of Non-Consequential Load Loss in Year One of the Planning Assessment, BPA believes that assurance received from the applicable regulatory authority or governing body responsible for retail electric service issues is adequate and submission to the ERO for a determination of adverse impact is unnecessary. The local utility and regulators are better positioned to determine adverse impacts on an individual system, whereas the ERO would have to develop a process and criteria for assessing adverse impacts.
Individual
Terry Harbour
MidAmerican Energy Company
No
MidAmerican supports NSRF comments with one change. The proposed NSRF addition of “consideration of planned outages at demand levels for which the outage would be performed” to the text of footnote “b” after “following Contingency events” should not be added. If the addition is made, a reasonable time frame clarification is necessary and should be added such as “greater than 6 months”. The proposed change would then read “consideration of planned outages greater than 6 months or longer at demand levels for which the outage would be performed”.
Yes
However, see the NSRF comments
No
See the NSRF comments
No
Item III of Attachment I should be deleted completely. Non ERO regulatory review is not necessary. Applicable regulatory authority or governing bodies responsible for retail electric service issues are stakeholders which may participate in the stakeholder process. Further, there are concerns compliance may not be possible because item III makes non-NERC applicable regulatory authorities or governing bodies responsible for retail electric service issues part of a NERC mandatory compliance without consequence to the said non-NERC governing bodies. Non-NERC entities are not constrained by NERC mandatory laws and penalties and aren't compelled to perform actions to meet NERC compliance. This opens a risk to any NERC regulated entities governed by such regulatory or governing bodies that do not or may not feel compelled to have a process for the NERC regulatory review specified in item III of attachment I.
See the NSRF comments

Individual
Andrew Gallo
City of Austin dba Austin Energy
Individual
Jason Marshall
New England States Committee on Electricity (NESCOE)
No
The New England States Committee on Electricity (NESCOE) appreciates the opportunity to comment on NERC's proposed revisions to Transmission Planning (TPL) Reliability Standards relating to permissible applications of planned load interruption. NESCOE is New England's Regional State Committee and is governed by a board appointed by the six New England Governors. These comments reflect the collective view of the six New England states. The issue of planned, limited load interruption rests at the central intersection of cost and reliability. It illustrates the fundamental balance that Commissioner Norris details in Order No. 762: the tradeoffs between "increasing levels of reliability and the costs that come along with achieving them." Transmission Planning Reliability Standards, Order No. 762, 139 FERC ¶ 61,060 (April 19, 2012) (Norris, Comm'r. concurring in part and dissenting in part) at 2. NESCOE agrees with Commissioner Norris that, as a general matter, this balancing should translate to a more explicit consideration of costs in the NERC standard development process. Id. at 1. The language in footnote "b"—and corresponding footnote 12 of TPL-001-2—implicitly recognizes cost considerations in transmission planning by tolerating limited load shedding under defined circumstances. NESCOE offers below comments and suggestions in response to the SDT's questions. These responses reflect NESCOE's interest in planning for a robust bulk electric system while taking into account the magnitude of risk that a solution is intended to address and the costs associated with competing solutions. NESCOE appreciates the work of the SDT in attempting to respond to the Commission's directives and the time constraints under which the SDT was required to make changes to footnote "b." However, NESCOE is concerned that establishing a bright-line maximum capacity threshold that is an absolute ceiling is overly prescriptive and unnecessary to meet the Commission's directives. In Order 762, the Commission rejected the contention that regional stakeholder processes should unilaterally determine the appropriate criteria to apply in planning to interrupt firm load. Order 762 at P 32. However, provided that technical parameters are in place, the Commission stated that it would be "amenable" to regional stakeholders establishing such criteria if, for example, NERC or the applicable Regional Entity "developed an exception process that provides flexibility in decisions based" on their expert view of regional considerations. Id. The SDT's proposal, however, would impose a one-size-fits-all requirement that forecloses a regional discussion of the quantitative and qualitative considerations that may justify an exception to the proposed 75 MW maximum capacity value. Such a regional discussion in ongoing in New England. In 2010, ISO New England introduced to stakeholders a draft Transmission Planning Load Interruption Guideline. The Guideline noted that load interruption should not be the principal tool to address transmission system reliability violations and highlighted the priority of reliable service. However, applying quantitative and qualitative criteria, the Guideline proposed for stakeholder discussion various levels of controlled load interruption in N-1-1 conditions—potentially up to hundreds of megawatts—that may be tolerated under clearly defined conditions. NESCOE did not take a view of the Guideline when it was presented for review and does not do so here. For now, the Guideline remains in draft form following stakeholder comment in 2011. However, imposition of a maximum capacity threshold that is an absolute ceiling for N-1 events and potentially, through revisions to footnote 12, N-1-1 events, would prematurely limit important regional discussions of this issue. A better approach, and one which the Commission appears amenable, would be to accompany any bright-line value with an exception process. There is recent precedent supporting such an approach: NERC proposed changes to its Rules of Procedure to accommodate exceptions to the proposed 100 kV bright-line Bulk Electric System definition. Separately, the footnote references Attachment 1 to the respective planning standards, which requires a stakeholder process review of the utilization of planned interruption. Such review is only triggered if utilization is sought in the Near-Term Transmission Planning Horizon, even though the footnote permits utilization of load interruption throughout the planning horizon. NESCOE does not support this limiting language, which is at tension with an open and transparent planning process over the entire planning horizon. The term "Near-Term" should be stricken or further justification should be provided.
No
NESCOE appreciates the efforts of the SDT in developing a stakeholder process for considering the use of load interruption in system planning. NESCOE especially appreciates the heightened role accorded to states in light of jurisdictional issues raised by the prospect of shedding load and implications for retail customers. States must be intimately involved in weighing reliability considerations against the economic implications of alternative approaches. Regarding the language in Section I, see the comments above regarding striking "Near-Term" in this context. NESCOE also suggests that additional clarity is needed regarding the intended meaning of "applicable regulatory authorities or governing bodies responsible for retail electric service issues." This language potentially implicates state agencies beyond public utility commissions (e.g., state consumer advocates, attorneys general) and could create confusion for state agencies as well as transmission planners that are required to provide notice to such entities and, pursuant to Section III, provide a process for regulatory review. Instead, the SDT should revise the language to read "electric retail regulatory authorities," a term with clear meaning that the Commission has itself used. See, e.g., Order 719.

Yes
NESCOE agrees with the list provided in Section II. Regarding item #7, in the interest of explicit direction, NESCOE suggests adding at the end of the sentence the following language: "and cost comparisons of all alternatives."
No
NESCOE is concerned that the 25 MW minimum value for regulatory review lacks sufficient technical justification. NESCOE understands that the SDT used responses to data requests to establish this 25 MW value, which is based on the average number of MWs that entities applying footnote "b" reported using in transmission planning. This may be a good starting point, but additional analysis is warranted. Specifically, the analysis should consider a more direct nexus to the system, such as substation design criteria. Additionally, as detailed above, Attachment 1 should provide clarity regarding the meaning of "applicable regulatory authorities." Moreover, clarification is required regarding the initial triggering factor for regulatory review. Section III states that the regulatory review process is required before the footnote can be utilized in "Year One" of the planning horizon. Does this mean that such regulatory review only applies to year one or does it apply to year one and beyond? If the former, NERC needs to provide a clear rationale for restricting such review when limiting factors are already applied (i.e., voltages greater than 300 kV or a 25 MW minimum threshold value).
Group
Tri-State G&T
Chris Pink
1. It is not clear how transmission projects with long lead times (such as T-lines) would be handled by "Footnote b". In other words, it is not clear if it is acceptable for a TP to plan for shedding Firm Demand in the Near Term Planning Horizon without meeting the conditions shown in "Attachment 1" when a mitigating project is planned that cannot be constructed in the Near Term Planning Horizon. 2. NERC Functional Model definitions for Planning Authorities and Transmission Planners do not include the types of activities being proposed in "Attachment 1." As written, this standard mandates functions on functional entities that are outside those defined by the NERC Functional Model. 3. In the NERC Glossary of Terms, Interruptible Demand is defined as "Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment." The process described in Attachment 1 creates an agreement between stakeholders (aka "end-use customers") and their transmission providers for shedding Demand. Thus, if the process described in Attachment 1 is followed, the "Firm Demand" referenced in "Footnote b" would be reclassified as "Interruptible Demand." In essence, Firm Demand would not be interrupted. If this was the intention of FERC, NERC, and the Drafting Team, the standard should just state "Interruption of Firm Demand is not allowed." 4. It is not clear how section III of "Attachment 1" would be applied to entities that only deliver wholesale electric service and not retail electric service.
Individual
Frederick R Plett
Massachusetts Attorney General
No
Although I voted for this Footnote, I do have concerns. 1) There is no reliability benefit to the 75MVA threshold limit. There should be no limit in the standard – it should be between stakeholders to decide that limit, not nationally imposed. 2) Any such agreement to consider non-consequential losses should have no impact to the BES especially when maintained in a confined boundary. 3) This takes away local decision making of PUC/ Local Board decision making; 4) FERC's concern that a few entities would disguise the "stakeholder" process to shed load is unfounded and should not be applied on a continent-wide basis. FERC is trying to impose tighter standards than the industry wants.
Yes
Yes
No
The 75 MW and 25 MW limits do not belong there. It would be best if the limits were established by stakeholder consensus and by state rulemakings.
Individual
Richard Vine
California Independent System Operator

No
While we have voted in favor of supporting the changes to the footnote and to move forward with the adoption of the standard, we remain concerned that there is not a good foundation for concluding that loss of load over 75 MW poses a reliability risk to the system compared to some higher MW threshold. Instead, the 75 MW capacity threshold is simply based on the current maximum planned loss of Non-Consequential Load. While we support minimizing reliance on Non-Consequential Load Loss, there may be scenarios where such reliance is unavoidable in the near-term, and therefore may be needed until capital upgrades can be put in place. At a minimum, the footnote or standard should provide for an exception process, should it be necessary for a planned Non-Consequential Load Loss of greater than 75 MW.
Yes
There is no basis to support only allowing the utilization of the footnote in the Near-Term Transmission Planning Horizon of the Planning Assessment. The footnote itself should not explicitly restrict its utilization to only the Near-Term horizon. Often, in the long-term planning horizon, when approval for transmission addition or reinforcement cannot be obtained for a variety of reasons, utilization of the footnote is considered and adopted, subject to stakeholder's and regulatory authority's approvals. Note that it is impractical to add or reinforce transmission facilities in a near-term planning (e.g. Year One) time frame and hence the proposed provision does not allow for utilizing the footnote for the interim period before new or reinforced transmission facilities are put in place. We suggest to remove the word "Near-Term".
Yes
Yes
Despite a public consultation process that includes the regulator(s), the standard then calls for notification to the regulator(s) and only moving forward once the regulator indicates that it does not oppose the shedding of load ("once assurance has been received that…"). This is still requiring the regulator to do something, and could be problematic if no response is provided by the regulator. How would one address silence on the part of the regulator?
A concern with the new TPL-001-2 standard is what we see as being the elimination of the existing footnote c, the footnote that qualified Category C load shedding as "may be necessary". The wording under the new TPL-001-2 appears that load shedding is the unqualified expectation of the criteria for C contingencies.
Group
SERC EC Planning Standards Subcommittee
Jim Kelley
Yes
No
We recommend that up to 25 MW of planned interruption be allowed without triggering the need for a stakeholder process. Since the average use given in the survey was 19 MW and there is no evidence of harm to the BES reliability resulting from that use, there is no reason to require a stakeholder process for amounts less than 25 MW. This is consistent with the value cited in Section III.
No
We believe that item 1.b of Section II would contain CEII information and should have limited distribution. The appropriate non-disclosure agreements would need to be developed to prevent widespread publication of the information.
Yes
Individual
Randy MacDonald
NB Power Transmission
No
We disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard. Provided there is no widespread, adverse effect on the reliability of the interconnected bulk electric system, the effect on customers of a firm demand interruption is the responsibility of the applicable regulatory authority or its delegated agencies responsible for local transmission and retail service over the load to be curtailed.
No
The process in Attachment 1 is overly prescriptive. Attachment 1, if retained, needs only to stipulate that the proposed utilization of the footnote be reviewed through an open and transparent stakeholder process in compliance with the applicable regulatory authority oversight.
No

No
Individual
Laurie Williams
Public Service Company of New Mexico
Yes
No
PNM voted yes to the Standard as a whole but would like the SDT to consider the following concern: Part II.2.b of Attachment 1 that requires an assessment of the effect of the use of Non-Consequential Load Loss under Footnote B on the health, safety, and welfare of the community, and PNM believes that assessments of this nature are entirely subjective and will be difficult to comply with and even more difficult to audit. It is our belief that this criteria should be removed from the Standard prior to its ultimate submittal to NERC.
Yes
Yes
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Individual
Patrick Farrell
Southern California Edison Company
No
SCE believes that the maximum capacity threshold should be increased from 75 MW to 250 MW, as 250 MW is the limit utilized by the California Independent System Operator (CAISO) for a consequential load drop for a single contingency. The CAISO has a rigorous transmission planning process that allows it to plan for and permit load shedding up to 250 MW.
Yes
The Stakeholder Process in Section I of Attachment 1 is similar to the method effectively used by the CAISO to manage and incorporate stakeholder input in its annual transmission planning process.
No
SCE participates in the rigorous CAISO annual transmission planning process that considers the information included in the proposed Section II of Attachment 1. However, the proposed language in Section II.2.b. “Assessment of the effect of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community,” seems overly broad and confusing. The California Public Utility Commission (CPUC) and CAISO presently consider these items before approving transmission plans. It is unclear what type of information would be required in order to meet the seemingly broad request contained in Section II.2.b. SCE believes that the language of Section II.2.b. should be removed from Attachment 1, or alternatively, the language should be revised to specifically exempt critical loads, such as hospitals, fire department facilities, law enforcement facilities, and correctional facilities.
No
As applied to SCE’s service territory, Section III of Attachment 1 appears to require written acknowledgement and approval by the CPUC of each and every Firm Demand interruption authorized by the CAISO’s annual transmission plan. In California, the CPUC is notified of and invited to every CAISO meeting on transmission planning, but the CPUC generally does not provide specific written assurances or agreement on detailed elements of the CAISO transmission plan. SCE believes that a general approval of the overall plan from the regulatory body should be adequate.
Footnote “b”/Footnote 12 as currently written does not provide for an exemption to allow for the use of Firm Demand interruption as a short-term solution to transmission problems. Many entities would benefit from being allowed to use Footnote “b”/Footnote 12 as a temporary solution in response to construction delays until facilities to mitigate an N-1 contingency identified in a Planning Assessment can be installed. Under the current proposal, the stakeholder process will provide very little value in attempting to resolve such a problem. In fact, the current Footnote “b”/Footnote 12 could result in a stakeholder process that may actually slow the implementation of mitigation measures for the system.

Group
MEAG Power
Scott Miller
Individual
Donald Weaver
NBSO
No
We do not agree with setting a MW limit for non-consequential load loss. The allowable amount should be determined and approved by the jurisdiction of the area(s) whose load is affected. The intent of the TPL standard and this footnote is to ensure that if non-sequential load loss is accounted for or relied up to ensure BES reliability (as assessed in the planning horizon), that such a decision needs to be approved by the appropriate jurisdiction. Non-consequential load loss being applied or considered to achieve BES reliability in planning assessment is in itself not a BES reliability concern that rises up to a continent-wide reliability standard.
No
(1) The process presented in Section I of Attachment I is overly prescriptive. This Section needs only to stipulate that the proposed utilization of the footnote be reviewed through an open and transparent stakeholder process developed and/or approved by the jurisdiction (a Regional Entity or regulatory authority) of the area(s) whose load is affected area. (2) There is no basis to support allowing the utilization of the footnote in the Near-Term Transmission Planning Horizon of the Planning Assessment only. The footnote itself should not explicitly restrict its utilization to only the Near-Term horizon. Often, in the long-term planning horizon, when approval for transmission addition or reinforcement cannot be obtained for whatever reasons, utilization of the footnote is considered and adopted, subject to stakeholder's and regulatory authority's approvals. Note that it is impractical to add or reinforce transmission facilities in a near-term planning (e.g. Year 0ne) time frame and hence the proposed provision does not allow for utilizing the footnote for the interim period before new or reinforced transmission facilities are put in place. We suggest removing the word "Near-Term".
No
We do not agree with the need for Section II (and Attachment I as a whole) at all. The footnote, or Attachment I, should only stipulate that when Non-Consequential Load Loss is needed to ensure that BES performance requirements are met, then regulatory approval from local jurisdiction needs to be provided with demonstration that the approval was obtained through an open stakeholder process.
No
See our comments under Q2 and Q3, above.
Individual
Milorad Papic
Idaho Power Company
Yes
Yes
Yes
Yes
Group
Southern Company
Antonio Grayson
Yes
No
The complex stakeholder process described in Attachment 1 should be required only if the amount of planned load shed exceeds 25 MW or the contingency is greater than 300 kV. Since the average use given in the survey was 19 MW and there is no evidence of harm to the BES reliability resulting from that use, there is no good reason to require such a stakeholder process for amounts less than 25 MW. The stakeholder process should only be required for larger amounts of load.
Yes

Yes
Group
Western Area Power Administration
Brandy A. Dunn
No
We do not support a maximum threshold of 75 MW or any MW level. It is not appropriate to enforce a one size fits all maximum value. There are no apparent reliability benefits from implementing a capacity loss limitation...why not pick 300 MW? Also we are not sure what prompted the additional distinction of allowing the load shedding only in the near-term planning horizon...please elaborate.
No
A public process seems out of place in a reliability standard.
Yes
No
See answer to Question 1.
Individual
Jack Stamper
Clark Public Utilities
Individual
Tom Hanzlik
SCE&G
Yes
No
No, We recommend that up to 25 MW of planned interruption be allowed without triggering the need for a stakeholder process. Since the average use given in the survey was 19 MW and there is no evidence of harm to the BES reliability resulting from that use, there is no reason to require a stakeholder process for amounts less than 25 MW. This is consistent with the value cited in Section III.
No
We believe that item 1.b of Section II may contain Critical Energy Infrastructure Information (CEII) and should have limited distribution. The appropriate non-disclosure agreements would be required in order to prevent widespread publication of the information.
Yes
While the current revisions improve the processes described, we have concerns regarding the revisions to TPL002-1 b. SCE&G has significant concern with the proposed revision to TPL Table 1, Footnote B. The current Footnote B states "Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems". The phrase "without impacting the overall reliability of the interconnected transmission systems" is important to the TPL standards to ensure that ERO standards do not dictate the level of service to specific customers. Service to specific customers and load pockets is jurisdictional to State Commissions. ERO standards should not compromise this jurisdiction. SCE&G believes that any proposed revisions to Footnote B must maintain the concept that planned or controlled interruption of electric supply to customers, whether they are radial or network, is allowed as long as it does not impact the overall reliability of the interconnected transmission systems. The proposed revision eliminates this concept
Individual
Kathleen Goodman
ISO New England
No
The draft footnote states that interruption "is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1." Attachment 1 appears to impermissibly require State participation in federal transmission planning processes. Further, it places the ERO in a Transmission Planning role, which exceeds the limits of the ERO's functions under Section 215 of the Federal Power Act. The current language

appears to conflict with (1) federal statutes that are clear that wholesale electric transmission issues are matters of federal, and not state, jurisdiction, (2) orders of the Federal Energy Regulatory Commission ("FERC") regarding the role and independence Regional Transmission Organizations ("RTOs") with regard to transmission planning, and (3) Section 215 which limits NERC's authority to regulate "users, owners and operators" of the Bulk-Electric System. Further, the conditions appear to conflict with Section 215 of the Federal Power Act by placing the ERO in a transmission planning role and providing it with regulatory or functional oversight regarding the substance of transmission planning decisions. The ERO has the authority to develop and enforce standards, but is not a transmission planning entity and does not have the authority to substitute its judgment for registered Planning Authorities and Transmission Planners regarding the planning or operation of the bulk power system. Where a review is sought of planning entities' determinations, per FERC-filed Tariffs, they may be brought before FERC under Section 206 of the Federal Power Act. Because the footnote, and the associated Attachment appear to be in conflict with FERC Tariff and other statutory provisions, they should be removed. The footnote itself states, "An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events." The objective statement within the standard does not appear to create a requirement and should be removed.
Yes
No
Section II, 2.a states that studies must address the estimated number and type of customers affected by Non-Consequential Load Shedding. This language should be removed for three reasons. (1) This appears to be inappropriate for a reliability standard. The specific number and type of customers within a set number of MWs that are electrically acceptable do not impact the reliability of the bulk electric system (as defined by Section 215 of the Federal Power Act). (2) Even if the number and type of affected customers were an appropriate process question for an ERO standard, the number and type of customers may change depending on particular system configuration at the time of the load shedding. For example, a substation may be reconfigured to address other system issues such as maintenance and a certain number of MWs of load being interrupted, while still electrically acceptable from a system reliability perspective, may impact different numbers and types of customers. (3) Assuming that the number and type of customers affected were an appropriate metric, the Transmission Planner in many cases will not be the appropriate entity to address these concerns. The Transmission Owner, Distribution Provider or Load Serving Entities would be the appropriate entities to address customer affects. Section II, 2.b should be revised to delete the reference to "health, safety, and welfare of the community." It is inappropriate for a NERC Standard to require planners to address the "health, safety, and welfare of the community." NERC's authority appears limited to regulating the "reliability" of the bulk electric system. Section 215 specifies that NERC's authority it to establish Reliability Standards necessary to ensure an "adequate level of reliability." Reliability Standards may specify the "design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation." Section 215 defines "reliable operation" as "operating the elements of the BPS within equipment and electrical system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements." Establishing this requirement is also arbitrary, because it is inconsistent with other transmission planning requirements. For example, the same load could be shed directly as the consequence of a fault and no such assessment is required. In addition, Transmission Planners can plan for the shedding of radial load with no assessment of health, safety and welfare. Section II, requirements 3 and 4 discuss estimating frequency and duration of Non-Consequential Load Loss based on historical performance. This provision is inconsistent with the manner in which transmission system planning is conducted and should be removed. The transmission system planning process uses deterministic not probabilistic assessments. While a power system may utilize these factors in assessing where the use of non-consequential load loss may be acceptable in terms of providing service, these factors do not inform reliability risks to the bulk electric system where the loss of load is found to be electrically acceptable in terms of system reliability (i.e., no thermal, voltage, or stability issues are created or exacerbated and no instability, uncontrolled separation, or cascading failures result).
No
This provision violates both the federal and state jurisdictional split over transmission facilities, and would violate several FERC orders directing the independence of RTOs in the regional system planning process. Said another way, the determinations of a federal transmission planning entity may not be required through an ERO standard to be subject to non-jurisdictional review and approval by state entities. Further, the provision violates Section 215 of the Federal Power Act, as the ERO cannot require the review of a particular transmission system plan by state entities. The following language should therefore be deleted from Section III of Attachment 1: "Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Non-Consequential Load Loss under footnote 12… ." Overall, the order of Section III is also notable. During year, two through ten of the overall planning horizon the standard allows for Non-Consequential Load Loss without state approval. In the first year of the assessment, approval becomes required for Non-Consequential Load Loss. In year one, even if mandating state participation and decisional authority in a federal planning process was legally

permissible, it is too late to allow for any other alternative as transmission planning, siting and construction of non-load loss alternatives would not be completed in the needed period. If there were non-load loss alternatives available, the use of non-consequential load loss would not be necessary, but it would also not be part of a transmission plan. The Regional Entities with NERC oversight perform periodic audits and require self-certification of the planning process. By virtue of the audit and self-certification process, NERC has the ability to monitor the use of Non-Consequential Load Loss in planning assessments. In addition to being notable for the year one timing, Section III seems incomplete. In the case where there is objection to Non-Consequential Load Shedding, the process appears to end without resolution. The submission to the ERO "for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss" conflcts with federal law and orders of the Federal Energy Regulatory Commission. As noted above, the ERO is not a planning entity and does not have authority to displace the reliability planning performed by planning entities. Transmission planning entities are those directed by FERC to make the determinations regarding adverse reliability impacts. If any entity wishes to challenge those determinations, it may do so before FERC under Section 215 of the Federal Power Act. Further, this provision would conflict with orders of the FERC regarding the independence of RTOs to conduct the regional transmission planning process. A reliability standard may not change the scope or meaning of federal statutes nor may it contradict or collaterally attack orders of the Federal Energy Regulatory Commission. For these reasons, this provision should be removed from the attachment to the proposed standard.
In summary, the main footnote is unobjectionable, but this standard as proposed has misplaced jurisdictional authority under Section 215 of the Federal Power Act for both states and the ERO through several of the process points and conditions set out in the attachment to the stardard. The removal of references is required for the standard to comport with the law. These revisions to the standard can be made, which would then allow the draft standard to comply with FERC's further guidance and the other legal limitations described above.
Group
Florida Municipal Power Agency
Frank Gaffney
No
FMPA has two issues: 1. What is the technical justification for 75 MW? There is no other metric in use similar to it. FMPA believes that, if the stakeholder process reveals that the stakeholders are willing to accept decreased service continuity to save money on their electric bills, why should that be limited to 75 MW which has nothing to do with BES reliability. BES reliability will not be impacted until load shedding gets near to the largest single loss of source contingency in relation to supply / demand mismatch. Other standards have chosen the low value of 300 MW as indicative, (e.g., CIP v5 for UFLS, EOP-004 for disturbance reporting); hence, FMPA recommends that the maximum amount of load shedding be 300 MW. 2. The footnote should also address a process whereby the transmission customer agrees to conditional firm service if the Transmission Planner / Transmission Service Provider (TSP) plans on curtailing firm service to that customer following a single contingency. The TSP should not be able to unilaterally degrade service from a state where it was not conditional to a state where it is conditional.
Yes
Yes
No
See FMPA Comments regarding the 75 MW threshold of Question 1.
Individual
Larry Watt
Lakeland Electric
Individual
Chantal Mazza
Hydro Québec TransÉnergie
No
Dropping load in the general sense should not be endorsed, but it is recognized that there are special situations where it cannot be avoided. Provided there is no widespread, adverse effect on the reliability of the interconnected BES, the effect of a firm demand interruption on customers is under the purview of the applicable regulatory authority that is responsible for local transmission and retail service over the load to be curtailed, and the TPL standard should not put a limit at 75 MW.
Even if the SDT said it is not in its scope, the following difficulty with the application of note 12 needs to be addressed by NERC. There are no limit on non-consequential load loss for Single Contingency P2-2, and P2-3. (HV

only), multiple Contingencies P4 and P5 (HV only), and P6 and P7. The note 12 allows limited non-consequential load loss for single contingency P1, Multiple Contingency P3. Non-consequential load loss is not allowed for P2-2 and P2-3. (EHV), and P4 and P5 (EHV). Considering the EHV Facilities, it is not reasonable to accept some non-consequential load loss for single contingency P1 and P2-3, and then deny it for Multiple Contingency categories P4 and P5 which are statistically less frequent than the former. Also, the Multiple Contingency P7 (for which there is no limit on non-consequential load loss) is more frequent than P2-3, P4 and P5. This technical irregularity must be reviewed and addressed.
Individual
Kayleigh Wilkerson
Lincoln Electric System
Yes
Yes
While supportive of Section III, LES believes the language in the last paragraph could be further enhanced with the following changes [located in brackets] to ensure a complete and accurate record is provided to the ERO. "Once [written] assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Non-Consequential Load Loss under footnote 'b', the Planning Coordinator or Transmission Planner must submit the [written assurance and] information outlined in items II.1 through II.8 above to the ERO…”.
Group
National Association of Regulatory Utility Commissioners
Holly Rachel Smith, Assistant General Counsel
No
As NARUC stated plainly in its Comments filed in FERC Docket No. RM11-18 (Dec. 20, 2011), “not only does the law require that the States maintain authority over distribution level reliability, States are in the best position to guide load shedding so that it has the least negative impact on the State’s customers and the operation of the local distribution system.” Id at p. 4. Given the twin responsibilities of FERC to maintain bulk system reliability and the states to ensure reliable and affordable service to retail load, NARUC supports the portion of the standard that requires notification and consultation with state and local regulators. However, the maximum capacity threshold (set at 75 MW) is problematic. In this instance, it appears that the 75 MW maximum capacity threshold is merely a reflection of antidotal information from five data request responders and as such is not technically justified. NARUC is not poised to offer an alternative; given that the state/local regulator is consulted in this process, the maximum capacity threshold should just be dropped. States should be able to authorize an 80 MW exception, or whatever level is reasonable, under specific circumstances if local economics and reliability warrant it.
No
It appears that the 25 MW minimum value is merely a reflection of antidotal information from a small number of data request responders and as such is not technically justified. NARUC is not poised to offer an alternative; given that the State/local regulator is consulted in this process, States should be appraised if any load is anticipated to be shed under any planning criteria. Thus, no mimimum value should be set.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery - NERC Realiability Compliance Coordinator
Individual
Mark Westendorf
Midwest Independent Transmission System Operator, Inc.
No
No. We believe footnote b in NERC TPL 002-1 and/or footnote 12 in TPL-001-2 should be eliminated because the intent of these standards is not to rely on non-consequential firm load shedding after a single contingency event. However, if these footnotes are not eliminated, there should be some limitation on how much firm load shed is allowed. We object to any level higher than the proposed 75 MW level and would prefer a level below 75 MW, but won’t object to the proposed 75 MW level if the footnotes are not eliminated.
No

No. MISO objects to a stakeholder process as outlined in Attachment 1. See our comments under Question 5.
No
No. MISO objects to a stakeholder process as outlined in Attachment 1. See our comments under Question 5.
No
No. MISO objects to a stakeholder process as outlined in Attachment 1. See our comments under Question 5.
We do not support using a stakeholder process to determine if Non-conseqeuntial Load Loss is appropriate following a single contingency event as a means to satisfy the standard. Stakeholder processes will nearly always result in disagreements. The parties that may be responsible for payment of upgrade costs will not necessarily line up with the parties adversely impacted by the alternative load loss. If the stakeholder process includes all stakeholders, there may be many more stakeholders impacted by upgrade costs based on broader benefits and/or cost sharing than stakeholders impacted by the alternative load loss. This will result in the majority decision of a stakeholder body to most often be one that supports load shed (until it is their turn to be the load that is shed). On the other hand, if the stakeholder process is limited to only the stakeholders directly impacted by the proposed load shed, to the extent those stakeholders pay only a small part of the upgrade costs, they will always select a potentially costly upgrade to avoid load shed. The point is, we do not believe that it possible to have a fair and impartial stakeholder process to correctly determine if and when load shed is acceptable to assist in satisfying a single contingency standard. Since the general intents of the existing TPL-002-1 standard and proposed TPL-001-2 standard are not to rely on any shedding of non-consequenital load to meet a single contingency event, in the event that footnote b of TPL 002-1 or footnote 12 of TPL 001-2 is not eliminated, we believe that it should be narrowly focused only on those situations for which the original footnote was developed: interruption of service to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, where the overall reliability of the interconnected transmission system is not impacted. We propose that footnote b and footnote 12 be modified as follows to ensure it is not misapplied: "An objective of the planning process is to avoid Non-Consequential Load Loss following Contingency events. In limited circumstances, Non-Consequential Load Loss may be needed within the planning horizon to ensure that BES performance requirements are satisfied. However, Non-consequential Load Loss cannot be used to avoid cascading outages or to maintain system stability. Non-consequential Load Loss also cannot be used to avoid a thermal loading or voltage limit violation on an EHV facility. When Non-Consequential Load Loss is utilized within the planning horizon to address BES performance requirements, such interruption cannot exceed 75 MW and is limited to the following circumstances: • Non-consequential Load Loss is allowed for load served by a radial transmission line to avoid voltage limit violations on the radial transmission line following a single contingency event anywhere on the system.. • Non-consequential load shed is allowed for load within a local area served by not more than two transmission lines and/or transformers to avoid a thermal loading issue or voltage issue in the local area, including the transmission lines and/or transformers supplying the area, for a loss of one of the transmission lines or transformers supplying the area, so long as there are no thermal loading or voltage violations outside the local area." We believe the language above maintains acceptable reliability on the bulk electric system by limiting load shed and violations that require load shed to radial areas or areas that would be served radially following the single contingency. We therefore highly recommend that Attachment I be eliminated entirely and that the footnotes either be eliminated or replaced with the modified version above.
Individual
Dan Inman
Minnkota Power Cooperative
No
1. MPC QUESTION: If a portion of the non-consequential load loss used to mitigate a contingency is controllable by a demand side load management system, can it be excluded from the "Firm Demand interruption" in TPL-002-1c Table I footnote 'b' and/or "Non-Consequential Load Loss" in TPL-001-2a Table 1 footnote 12? a. Would this load count towards the 25 MW and 75 MW thresholds? b. Would it have to be curtailed on a pre-contingent basis in order to be excluded from the non-consequential load total, or can it be excluded even if the curtailment happens through action of the UVLS? c. RECOMMENDATION: When describing "interruption of firm demand" or "non-consequential load loss" in footnote 'b' add the language "not counting load shed on a pre-contingent basis". This would be added to the last sentence of footnote 'b' if it indeed should not be counted towards the 75 MW threshold. Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion. 2. MPC QUESTION: If multiple companies own portions of the non-consequential load loss used to mitigate a contingency at a single substation, does each company's load count towards the 25 MW and 75 MW thresholds or does the total load at the substation count? a. EXAMPLE: 100% of the load at a substation is set to trip with automatic UVLS. Company A, B, and C own load amounts X, Y, and Z at the substation. i. Is the amount of load counted towards the 25 MW and 75 MW thresholds X+Y+Z, or is each counted separately? b. RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote 'b' could read "In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW from one entity." Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion.

No
1. MPC QUESTION: In Attachment 1 Section I, what is the definition of a "stakeholder"? a. Is this intended to apply to multiple NERC functional entities (DP, TO, TOP, LSE), public residential customers, and/or business owners that are affected by system contingencies? b. RECOMMENDATION: Define stakeholder to be "affected Transmission Owners, Transmission Operators, Distribution Providers, and Load-Serving Entities." We believe it is most appropriate for the Transmission Owners, Transmission Operators, Distribution Providers, and Load-Serving Entities to objectively evaluate the risks of load shedding in a local area against the cost impact of a large transmission project on the rate base. 2. MPC QUESTION: In Attachment 1 Section I item 1, what does "including applicable regulatory authorities" refer to? a. Is this the same body that "applicable regulatory authority or governing body" refers to in Section III? b. Are these requirements still applicable if the 25 MW threshold in Section III is not passed? c. RECOMMENDATION: Attachment 1 Section I Item 1 could read "… including applicable regulatory authorities or governing bodies responsible for retail electric service as described in Section III. A clearly defined statement allows the Transmission Planner and Planning Coordinator to identify the appropriate parties to be included in every instance Attachment 1 is used.
No
1. MPC QUESTION/COMMENT: In Attachment 1 Section II item 2b, "Assessment of the effect … on the health, safety, and welfare of the community" is vague. Clarification is requested. a. RECOMMENDATION: Remove Item 2b because it requires the assessment of the footnote application impact on the potential health, safety, and welfare of the community. These types of assessments should be eliminated because they are not electric system reliability matters and were not stipulated by FERC. In the event that the Standards Development teams choses to keep item 2b, then add language semi-defining this as follows in Attachment 1 Section II Item 2b "...health, safety, and welfare of the community as determined by impact on critical health and emergency services." This allows the Transmission Planner and Planning Coordinator to identify the appropriate parties affected by the contingency to be analyzed in every instance Attachment 1 is used.
No
1. MPC QUESTION: In Attachment 1 Section III, what is the definition of "applicable regulatory authority or governing body"? a. Is this the state Public Service Commission or Public Utilities Commission, the Regional Reliability Organization (RRO), and/or the Reliability Coordinator (RC)? b. RECOMMENDATION: Depending on the answer to the above question, define "applicable regulatory authority or governing body" more precisely. The language could read "applicable regulatory authority or governing body responsible for retail electric service such as the state Public Services Commission or Public Utilities Commission". A clearly defined statement allows the Transmission Planner and Planning Coordinator to identify the appropriate parties to be included in every instance Attachment 1 is used. 2. MPC QUESTION: In Attachment 1, if non-consequential load loss is planned at multiple bulk delivery points to mitigate the same contingency should the total load loss count towards the 25 MW and 75 MW thresholds or should the loads be counted individually? a. EXAMPLE: There are two load serving substations (X load at substation B and Y load at substation C) on a long 115 kV line with 230/115 kV transformation at each end (substation A and substation D). Automatic under-voltage load shedding is in place at substations B and C, the UVLS relays at each substation making load trip decisions based on local voltage (i.e. independent operation). If one end of the 115 kV line trips and 115 kV voltage is below allowable levels at both substations X and Y, then the total load tripped by UVLS will be X+Y. i. Does the X+Y value count towards the 25 MW and 75 MW thresholds or are X and Y counted separately? ii. What if X load is dropped for one contingency and Y load is dropped for a different contingency, is the total load counted X+Y or each load separately? b. RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote 'b' could read "In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for any single contingency." Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This clarification would explain much more clearly what is counted towards the two thresholds and decrease confusion. 3. MPC QUESTION: In Attachment 1, if UVLS relaying is programmed at a sub to trip the load in stages at multiple voltage setpoints, such that only a fraction of the load is tripped for a given contingency, is the entirety of the load still counted towards the 25 MW and 75 MW thresholds? a. EXAMPLE: Substation B has X load that will trip if the BES voltage gets to 0.92 p.u. and Y that will trip if the BES voltage gets to 0.88 p.u. i. If only X amount of load is required to mitigate a single contingency in the near-term TPL assessment, is X load counted towards the 25 MW and 75 MW thresholds or is X+Y load counted? ii. Is there a difference if the Y load is at a different, nearby substation with both loads having the aforementioned tripping logic? b. RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote 'b' could read "In no case can the planned Firm Demand interruption under footnote 'b' (as demonstrated in the near-term horizon analysis) exceed 75 MW at a single substation." Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion.
1. MPC QUESTION: In TPL-002-1c Table I and TPL-001-2a Table 1 can "Firm Demand interruption" or "Non-Consequential Load Loss" be initiated by a manual event, such as operator action, or does it need to be automatic, such as Under Voltage Load Shedding? a. RECOMMENDATION: In TPL-002-1c Table I footnote 'b', add a sentence stating "Acceptable methods to enact Firm Demand Interruption may include manual or automatic processes that can be initiated within a reasonable timeframe"
Individual

Bob Casey
Georgia Transmission Corp
Yes
Yes
Yes
Yes
Individual
Michael Falvo
Independent Electricity System Operator
No
We disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard. Provided there is no adverse effect on the reliability of the interconnected bulk power system, the effect on customers of a firm demand interruption is the responsibility of the applicable regulatory authority or its agencies responsible for local transmission and retail service over the load to be curtailed. We propose replacing the sentence, in the footnote and in attachment one, section III that reads: "In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW." with "In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss under footnote 12 for a Registered Entity that is a Canadian Entity (or a Mexican Entity) should be implemented in a manner that is consistent with/or under the direction of the Applicable Governmental Authority or its agency in Canada (or Mexico).
No
No. The process presented in Section I is overly prescriptive. If a section that prescribes the principles of a stakeholder process is required, then for Canadian entities this section should simply state that any threshold should be established in a manner consistent with other service levels that apply to local transmission and retail service for the load to be curtailed. Corrective action plans can rarely be implemented in a one-year time frame, and in some cases, limited use of Non-consequential Load Loss will be preferable to unaffordable transmission enhancements, therefore we believe that the use of footnote 'b'/'12' should not be limited to the Near-Term Transmission Planning Horizon. We propose that the phrase "the Near-Term Transmission Planning Horizon of" be deleted from the opening paragraph.
No
No. The process presented in Section II is overly prescriptive. If a section that prescribes the information requirements for a stakeholder process is required, then for Canadian entities this section should simply state that any threshold should be established in a manner consistent with other service levels that apply to local transmission and retail service for the load to be curtailed.
No
No. The process presented in Section III is overly prescriptive and requires information not necessary to the intended purpose. As state in Q1, we disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard, and propose alternate language as stated in Q1 comments. If this section must deal with a review of the use of footnote 'b'/'12' to ensure that there are no adverse reliability impacts on the bulk power system, then it should be limited to the information required for that purpose. Provided there is local support for the use of Non-Consequential Load Loss under footnote 'b'/'12', only information items 6 and 8 from section II are relevant for this assessment—the remainder are not required for this section and should be deleted. As stated in Q2 above, the use of footnote 'b'/'12' shouldn not be limited to the Near-Term Planning Horizon. We propose that the words "in Year One of the Planning Assesssment"be deleted. Items 1 and 2 complicate this section and are unneccesary. They should be replaced by a phrase such as "for those planning events where the use of footnote 'b'/'12' is referenced". We disagree with the need to submit to the ERO for a determination of whether there are any adverse reliability impacts caused by the use of Non-Consequential Load Loss. This will introduce a new type of review at the ERO that will create uneccesary delays and burden, and is inconsistent with and not required for all of the other performance requirements in the TPL standards. Submitting the analysis to the adjacent Planning Coordinators and Tranmission Planners, and any functional entity that requests it, as called for in requirement R8 of TPL001-2 should be sufficient.
(1) We'd like to reiterate our support for allowing load interruption for a single contingency with sufficient review/oversight and under acceptable conditions, including no adverse impact on the reliability of the interconnected bulk power system. The reliability aspects (BES performance requirements) should be reviewed for acceptability by the adjacent Planning Coordinators and Transmission Planners. However, issues pertaining to

economics or externalities which may not be directly reliability-related are always available for review and debate by the stakeholders via the regulatory processes and subject to approval by the regulatory authority of each jurisdiction (including those in Canada and Mexico). (2) Furthermore, we request that Table 1 of TPL-001-3 (previous TPL-001-2 approved by NERC BOT) be corrected for EHV contingencies in P2, P4 and P5 categories to allow the application of footnote 'b'/'12' that is allowed for the P1 events. Events in P2, P4, and P5 can involve more elements and can be more onerous and stressful to the system than the P1 events, and if use of footnote 'b'/'12' is permitted in the less stressful P1 events, it should also be permitted in P2, P4 and P5 events. (3) We suggest that NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve it. Accordingly, we believe that the focus of footnote 'b', and footnote 12 should be that interruption of load must not have an adverse impact on the reliability of the interconnected bulk power system. A continent-wide standard should not concern itself with the reliability of supply or supply continuity for local load, as that is the responsibility of the applicable regulatory authority or its agencies responsible for local transmission and retail service over the load to be curtailed. As mentioned above, NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve it. In this regard, we believe that Attachment 1 is not necessary because it prescribes a process which goes beyond the outcome of the standard and dictates how stakeholdering must be carried out. The individual jurisdiction should establish the process for ensuring compliance with the standard and decide to what extent a stakeholdering process is necessary to establish the acceptable level of load rejection for the area in a manner consistent with local transmission established service levels.
Group
National Grid
Michael Jones
No
The 75MW of Firm Demand interruption is retail load that is being dropped. Dropping load in the general sense should not be endorsed, but it is recognized that there are special situations where it cannot be avoided. If a regulator responsible for retail load is comfortable with greater than 75MW being dropped in a rare situation, there should not be a requirement to build out of the situation. Provided there is no widespread, adverse effect on the reliability of the interconnected BES, the effect of a firm demand interruption on customers is under the purview of the applicable regulatory authority that is responsible for local transmission and retail service over the load to be curtailed. There is no technical basis for the 75 MW figure with respect to reliability impact. Although, the value was developed by the SDT as a result of their review of Section 1600 Data Request, there was no reliability based analysis performed to identify whether the 75 MW is reasonable number. It is possible that a number either larger or lower could be identified if a reliability and cost-effective analysis is conducted.
No
The current document includes the language: 2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW. This gives no concept of how long customers could expect to be out of service and hence whether this would be an appropriate approach. Suggest using a value that is based on energy, i.e., MWh. A value of 600MWh would represent 25 MW out for 24 hours, or could be 60 MW out for 10 hours, etc. This would seem to provide a more valuable understanding the true impact to customers in assessing the health, safety and welfare. It is also expected that if Demand Resources are being used that they would be excluded from the term "non-consequencial" load, and that the value being discussed is only that in addition to any Demand Resources being used.
Group
Iberdrola USA
John Allen
No
"Contingency events" should be replaced by "Planning Events." Why would load shedding be limited only for certain circumstances in the Near-Term Transmission Planning Horizon? The Near Term is likely the period when the least can be done to avoid load shedding due to the time required for permitting and construction of facilities. A maximum capacity threshold is reasonable, whether 75 MW or a lower value.
No
"Stakeholders" is undefined – would this be the same stakeholder body identified in the planning process of the Open Access Transmission Tariff?
No
Regarding the documentation required for item 2.b, how are "health, safety, and welfare of the community" to be assessed? What are the metrics? How would compliance with this provision be evaluated?
No
Why would a retail service regulator approve a 300 kV and above performance issue?

A one-paragraph footnote encompassing a 2-page attachment is cumbersome for a Reliability Standard.
Group
ACES Power Marketing Standards Collaborators
Ben Engelby
No
(1) We disagree with placing an upper limit on the amount of firm load shed. Conceptually, it seems like a good idea but we do not believe that such a threshold could ever consider all of the potential issues that could arise and would cause the need to plan to shed firm load. This is especially true considering that the SAR clarifies that the upper threshold will be based on the existing planned load shedding values. Future issues cannot be considered by the information contained in the data request. Consider a situation in which a new transmission line was included in Planning Assessment but cannot be built because right of ways cannot be obtained. Should an upper limit be placed on planned load shed in such a situation? (2) We disagree with the threshold of 75 MW. In Order No. 762, the Commission discussed the "blend concept," where it "envisioned the planner would consider up to 100 MW of planned Firm Demand interruption along with other options to resolve the system performance criteria violation and submit its documentation and explanation to the entity deciding whether the planned load shed is acceptable." (emphasis added) Even the Commission envisioned using higher thresholds. Furthermore, the data appears to show that one instance of Non-Consequential Load Loss would be immediately out of compliance because it is actual 75.2 MW not 75 MW. If the upper threshold is too close to 75 MW, any load growth might also compel the instance to be disqualified. If the SDT plans to keep the upper limit, we suggest increasing the amount to at least 100 MW.
No
(1) Many RTOs have well organized stakeholder processes that could be utilized to satisfy Attachment 1. Because the TPL standards apply to both the PC and TP, one may conclude that both functions need to have a stakeholder process. Rather, we think that the TP should be able to rely on its PC's stakeholder process. We recommend clarifying Attachment 1 that it is acceptable for the TP to rely on the PC's process and that both entities are not required to have redundant processes. The most important point is that stakeholders have an opportunity to participate.
No
(1) Adding the word "effect" on the health, safety, and welfare of the community creates more confusion regarding what is needed for the assessment. We recommend removing the effect clause from Section II. (2) We disagree that the Transmission Planner should be required to provide an assessment at all on the health, safety and welfare of the community. Attachment 1, Section 2a identifies the types of customers that are impacted without needing a formal assessment. Stakeholders will have an opportunity to provide information on impacts of planned load shedding through either the Transmission Planner's stakeholder comment process or through the local regulatory agency's stakeholder comment process. Further, these planned interruptions of firm demand are expected to be short in nature so any impact would be de minimis. Finally, an assessment on the health, safety and welfare of the community is an unnecessary burden on the registered entity and is better suited for local governments that can speak through the stakeholder process. (3) Bullet 3 is based on available historical information. While this seems reasonable, we have concerns because of the rare instances that Non-Consequential Load Shed actually occurs. If a TP uses Non-Consequential Load Shed for the first time, there is no historical information. What would be an acceptable basis for the first use of Non-Consequential Load Shed when the entity is without historical information? (4) Expected time duration of the planned load shed is too speculative and should not be required because any duration will likely be a guess. When actual contingencies occur, the time of restoration varies and any time that was selected prior to the event is not likely to be correct. We do not see the value in predicting the duration time because there is too much uncertainty about how long an outage will really last. The SDT needs to clarify what is expected for the duration of the planned load shed. (5) While we appreciate that the response to our comments clarified the intent is that "Possible future plans could include a decision not to mitigate the need for Firm Demand interruption," the language in the Attachment simply does not reflect this. The Attachment specifically states "Future plans to mitigate the need for Non-Consequential Load Loss." A decision not to mitigate the need for Firm Demand interruption is not a future plan to mitigate. Consequently, Attachment 1, section II.5 will need to be modified to implement this intent. Otherwise, this language is certain to be interpreted as requiring a mitigation plan.
No
(1) We disagree with the threshold of 75 MW, as mentioned above.
(1) The SDT needs to consider the connection between the developing standards to maintain and improve reliability with the costs required to meet those standards. We believe there is an imbalance of the costs associated with meeting compliance for the current draft standard with proposed benefit of maintaining reliability of the BPS. This standard is a good candidate for the CEAP initiative to determine the cost benefits of reliability. (2) The standard needs to allow more flexibility regarding the use of planned load shed to address transmission performance issues in the planning horizon. It needs to recognize that these planned load shedding events may only be preliminary decisions for addressing problems that are several years away. If there is little chance that the planned shed load will ever be relied upon in the operating time horizon, there should be much less stringent requirements. For instance, if a PC or TP relies on planned load shed for year five of the planning horizon but year

one does not utilize the planned load shed, they have four years to develop another solution. Why should an entity expend great effort and resources for year five when another solution will likely be developed within that time period? (3) What does “materially changed” mean and what degree of a change would be considered material in the Attachment 1 stakeholder process? The SDT should clarify specific conditions in Section II that would constitute a material change. (4) Thank you for the opportunity to comment.
Individual
Richard Bachmeier
Gainesville Regional Utilities
Individual
Spencer Tacke
Modesto Irrigation District
No
I am voting NO because there is no technical basis for use of the 75 and 25 MW absolute threshold values, regardless of the size of the utility's load, referenced in the proposed standard. WECC's past experience with implementation of arbitrary magnitudes for requirements (e.g., the 5% and 7% arbitrary magnitude contingency reserve requirements), has proved to be problematic. I would suggest investigating a technical basis for using a relative requirement, such as percentage of the utility's load, maybe 5% and 2.5%, respectively, and that it be based on technical requirements similar to those found in Table 1 of the WECC Criteria TPL-001-WECC-CRT-2. Thank you.
Yes
Yes
No
I am voting NO because there is no technical basis for use of the 75 and 25 MW absolute threshold values, regardless of the size of the utility's load, referenced in the proposed standard. WECC's past experience with implementation of arbitrary magnitudes for requirements (e.g., the 5% and 7% arbitrary magnitude contingency reserve requirements), has proved to be problematic. I would suggest investigating a technical basis for using a relative requirement, such as percentage of the utility's load, maybe 5% and 2.5%, respectively, and that it be based on technical requirements similar to those found in Table 1 of the WECC Criteria TPL-001-WECC-CRT-2. Thank you.
Individual
Jason Weiers
Otter Tail Power Company
Individual
Alice Ireland
Xcel Energy
No
Although the maximum capacity value is used for planning purposes, how does this correlate with operational standards/issues that may require that value be greater. The planning studies look at very specific seasonal conditions on the system and may not necessarily look at all the states of the transmission system during the normal business day. If an operational event requiring a greater value of Non-Consequential Load Loss (NCLL) is executed and the specific outage was not considered in a planning study, how will this affect compliance with the planning standard. There was no technical rationale by the SDT for selecting the maximum value, thus a limit should not be set and should be left as a general discussion issue in the Stakeholder Process due to the many unforeseen issues that may arise.
Yes
The possibility of NCLL is always present, whether in the planning or operational arena. Section I (#5) should however specifically state that in the dispute resolution process a stakeholder does not have right of refusal for NCLL. This should be especially true when a transmission project has been proposed and NCLL in the interim is required due to the regulatory process, equipment lead time, etc. preventing the completion of project at an earlier time.
No
Section II should be left as part of the resolution in the dispute process and should not be made a requirement. Some in particular include: § II.1. - this should be based only on applicable contingencies or conditions that could require NCLL. Having to include the estimated hours at or above a load level may not always be the most effective way to convey why NCLL will be used and adds little to the argument of why or why not it needs to be used. § II.2.a - This may not always be apparent to the TO serving a wholesale transmission customers (REC, MUNICIPAL,

etc.). This should be eliminated since it does little in emphasizing the need for NCLL. § II.2.b - The "effect" of the use of NCLL may not always be apparent, because it is a perceived condition of what could happen that can be interpreted differently. I agree that it should be mentioned in the Stakeholder process outlining the locations where NCLL will take place and let the dispute process identify and assess the health, safety and welfare of the community. How do you assess the effect in the Planning of NCLL. The effect should be identified by the party being affected and resolved in the dispute process. § II.3 & 4. - This needs to be eliminated. Expected frequency and duration of NCLL based on historical performance DOES NOT GUARANTEE future performance and does little in emphasizing the need for NCLL. II.8 - This should be addressed by the Regional Planning Authority in their regional studies.
No
It does not appear that an entity has any options if the applicable regulatory authority or governing body objects to the use of NCLL in year one. This could potentially occur as a result of load patterns and generation issues submitted by an LSE not necessarily having BES elements and the only solution is to implement NCLL. In year one, it is too late to build any necessary and NCLL may be the only alternative.
Setting limits on the amount of NCLL only sets the stage for failure in the compliance of NERC standards and fails to take note of what is really the issue; the planning of a transmission system that is both reliable and economically viable for all stakeholders and customers. It should be emphasized that the use NCLL in a “planning process” is only assuming the conditions set in the study will exist and in no way reflects the conditions seen during the day to day operation of the transmission system. Xcel Energy is concerned about the previous ability on loss of load in anticipation of the next outage (previously C3 now P6). For TPL-003, loss of load in anticipation of the next system outage was covered under footnote B. Footnote 9 now states, “…the re-dispatch does not result in any Non-Consequential Load Loss. “ This is a large increase in requirements of the transmission system to operate. As written, it appears that footnote 12 is NOT applicable to P6 contingencies. Please clarify is this is the intent.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Revision of TPL-002 footnote 'b' and TPL-001 footnote 12

The Project 2010-11 Drafting Team thanks all commenters who submitted comments on the proposed standards, TPL-002-1c and TPL-001-2a. The standards were posted for a 45-day public comment period from October 5, 2012 through November 19, 2012 with the initial ballot period from November 9, 2012 to November 19, 2012. There were 61 sets of comments, including comments from approximately 149 different people from approximately 112 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

Summary: The drafting team made the following revisions in response to comments:

TPL-002-1c: footnote b - ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load.

TPL-001-2a: footnote 12 **-** An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following ~~Contingency~~ planning events.

TPL-001-2a: footnote 12 - However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1.

Section II, Bullet 2b. ~~Assessment~~ An explanation of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community

Section II, Bullet #5. Future plans to ~~mitigate~~ alleviate the need for Firm Demand interruption under footnote 'b'

Section III, first paragraph: Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ~~assure~~ ensure that the applicable regulatory ~~authority~~ authorities or governing ~~body~~bodies responsible for retail electric service issues do~~es~~ not object to the use of Firm Demand interruption under footnote 'b' if either:

Section III, last paragraph: Once assurance has been received that the applicable regulatory ~~authority~~ authorities or governing ~~body~~bodies responsible for retail electric service issues do~~es~~ not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.

A number of respondents continue to question the legality of the proposed standards. The general line of thought in those comments is that NERC is imposing itself into the local planning process in violation of existing statutes. The SDT does not believe that to be the case and has responded accordingly to those commenters.

Many commenters questioned the use of a stakeholder process at all. Those commenters expressed the opinion that the FERC Order did not mandate the use of the stakeholder process. The SDT used the Board of Trustees approved standard as a starting point for this draft. FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach.

In addition, many commenters chose to question already approved facets of the proposed TPL-001-2a standard. These commenters are questioning the application (or non-application) of footnote 12 for various planning events. TPL-001-2 was previously approved by the industry and the NERC Board of Trustees. The SAR for this project took that approval as the starting point for the specific discussion of footnote 'b'/12 and does not allow for review of previously approved applications of the footnote.

The SDT is requesting that the project be moved to a successive ballot.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

NERC

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Christina Koncz	PSEG Power LLC	NPCC	5
10.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

11.	Michael Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec Transenergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Ben Wu	Orange and Rockland Utilities	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Team	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	Robert Rhodes	Southwest Power Pool	SPP	NA
3.	John Allen	City utilities of springfield	SPP	1, 4
4.	Don Taylor	Westar Energy	SPP	1, 3, 5, 6
5.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.				
3.	TOM BREENE	WPS	MRO	3, 4, 5, 6
4.	JODI JENSON	WAPA	MRO	1, 6
5.	KEN GOLDSMITH	ALTW	MRO	4
6.	ALICE IRELAND	XCEL	MRO	1, 3, 5, 6
7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9.	JOE DEPOOTER	MGE	MRO	3, 4, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	1, 3, 5, 6
12.	MARIE KNOX	MISO	MRO	2
13.	LEE KITTELSON	OTP	MRO	1, 3, 5
14.	SCOTT BOS	MPW	MRO	1, 3, 5, 6
15.	TONY EDDLEMAN	NPPD	MRO	1, 3, 5
16.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17.	DAN INMAN	MPC	MRO	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
4.	Group	paul haase	Seattle City Light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	pawel krupa	seattle city light	WECC	1
2.	dana wheelock	seattle city light	WECC	3
3.	hao li	seattle city light	WECC	4
4.	mike haynes	seattle city light	WECC	5
5.	dennis sismaet	seattle city light	WECC	6

				1	2	3	4	5	6	7	8	9	10
5.	Group	Greg Rowland	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3
3.	Dale Goodwine	Duke Energy	SERC	5
4.	Greg Cecil	Duke Energy	RFC	6

				1	2	3	4	5	6	7	8	9	10
6.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chuck Matthews	Transmission Planning	WECC	1
2.	Berhanu Tesema	Transmission Planning	WECC	1
3.	Melvin Rodrigues	Transmission Planning	WECC	1

				1	2	3	4	5	6	7	8	9	10
7.	Group	Chris Pink	Tri-State G&T	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chris Pink			
2.	Mark Stein			
3.	Janelle Gill			

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member
4.	Bill Middaugh

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Jim Kelley	SERC EC Planning Standards Subcommittee	X				X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Co	SERC	1
2.	Charles Long	Entergy Services	SERC	1
3.	Edin Habibovich	Entergy Services	SERC	1
4.	James Manning	NC Electric Membership Corp.	SERC	1
5.	Bob Jones	Southern Company Services	SERC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Scott Miller	MEAG Power	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Steve Grego	MEAG Power	SERC	5
2.	Steve Jackson	MEAG Power	SERC	3
3.	Danny Dees	MEAG Power	SERC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Utility Service	FRCC	3
8.	Stan Rzad	Keys Energy Services	FRCC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	David Dockery - NERC Realiability Compliance Coordinator	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

				1	2	3	4	5	6	7	8	9	10
12.	Group	Michael Jones	National Grid	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michael Schiavone	Niagara Mohawk (A National Grid Company)	NPCC	3

				1	2	3	4	5	6	7	8	9	10
13.	Group	John Allen	Iberdrola USA	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joseph Turano	Central Maine Power	NPCC	1
2.	Raymond Kinney	New York State Electric & Gas	NPCC	1

				1	2	3	4	5	6	7	8	9	10
14.	Group	Ben Engelby	ACES Power Marketing Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
2.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
3.	Amber Anderson	East Kentucky Power Cooperative	SERC	1, 3, 5
4.	John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
5.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
6.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1, 3, 4, 5

				1	2	3	4	5	6	7	8	9	10
15.	Individual	Tim Ponseti, VP	TVA Transmission Reliability Engineering and Controls	X								X	
16.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
17.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
18.	Individual	Brandy A. Dunn	Western Area Power Administration	X					X				
19.	Individual	Holly Rachel Smith, Assistant General Counsel	National Association of Regulatory Utility Commissioners									X	
20.	Individual	Thad Ness	American Electric Power	X		X		X	X				
21.	Individual	Kenn Backholm	Public Utility District No.1 of Snohomish County	X		X	X	X	X			X	

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
22.	Individual	Travis Metcalfe	Tacoma Power	X		X	X	X	X				
23.	Individual	Steven R. Wallace	Seminole Electric Cooperative, Inc.			X	X	X	X				
24.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
25.	Individual	James Tucker	Deseret Generation & Transmission	X				X					
26.	Individual	Melissa Kurtz	USACE					X					
27.	Individual	Chris Pink	Tri-State Generation & Transmission Association	X									
28.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
29.	Individual	John Collins	Platte River Power Authority	X		X		X	X				
30.	Individual	Don Jones	Texas Reliability Entity										X
31.	Individual	Kirit Shah	Ameren	X		X		X	X				
32.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
33.	Individual	David Kiguel	Hydro One Networks Inc.	X		X							
34.	Individual	Martyn Turner	LCRA Transmission Service Corporation	X									
35.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X	X				
36.	Individual	Patricia Robertson	BC Hydro and Power Authority	X	X	X		X					
37.	Individual	Terry Harbour	MidAmerican Energy Company	X		X		X	X				
38.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X					
39.	Individual	Jason Marshall	New England States Committee on Electricity (NESCOE)										
40.	Individual	Frederick R Plett	Massachusetts Attorney General								X		
41.	Individual	Richard Vine	California Independent System Operator		X								
42.	Individual	Randy MacDonald	NB Power Transmission	X									
43.	Individual	Laurie Williams	Public Service Company of New Mexico	X		X							
44.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
45.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
46.	Individual	Donald Weaver	NBSO		X								
47.	Individual	Milorad Papic	Idaho Power Company	X		X							
48.	Individual	Jack Stamper	Clark Public Utilities	X									
49.	Individual	Tom Hanzlik	SCE&G	X		X		X	X				
50.	Individual	Kathleen Goodman	ISO New England		X								
51.	Individual	Larry Watt	Lakeland Electric	X									
52.	Individual	Chantal Mazza	Hydro QuÃ©bec TransÃ‰nergie	X									
53.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
54.	Individual	Mark Westendorf	Midwest Independent Transmission System Operator, Inc.		X								
55.	Individual	Dan Inman	Minnkota Power Cooperative	X									
56.	Individual	Bob Casey	Georgia Transmission Corp	X									
57.	Individual	Michael Falvo	Independent Electricity System Operator		X								
58.	Individual	Richard Bachmeier	Gainesville Regional Utilities	X									
59.	Individual	Spencer Tacke	Modesto Irrigation District				X						
60.	Individual	Jason Weiers	Otter Tail Power Company	X		X		X					
61.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The SDT thanks you for your participation. Your support of comments from another organization has been noted.

Organization	Supporting Comments of "Entity Name"
Seattle City Light	Puget Sound Energy
MEAG Power	Snohomish County Public Utility District
Associated Electric Cooperative, Inc. - JRO00088	SERC EC Planning Standard Subcommittee
USACE	MRO NSRF
MidAmerican Energy Company	MidAmerican supports the NSRF comments
City of Austin dba Austin Energy	Tacoma Power and Snohomish P.U.D.
South Carolina Electric and Gas	South Carolina Electric and Gas - SCE&G
Clark Public Utilities	Snohomish County PUD and Tacoma Power.
Lakeland Electric	FMPA

Organization	Supporting Comments of “Entity Name”
Gainesville Regional Utilities	FMPA - Florida Municipal Power Agency
Otter Tail Power Company	Minnkota Power Cooperative

1. **Do you agree with the text in the body of the footnote including the maximum capacity threshold? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. For the maximum capacity item, please supply any technical rationale for your comment along with limiting conditions and any current criteria in use at your entity.**

Summary Consideration: The majority of the comments received for this question were handled with explanations of the SDT intent or clarifications of the constraints under which the SDT was working. There were a number of comments however concerning the justification of the threshold values. The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. DOE and other thresholds can be a point of reference or sanity check but in and of themselves are not sufficient for setting a threshold in this matter. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach.

There were several comments regarding the application of footnote 12 within Table 1 of proposed TPL-001-2a. Such discussion is out of scope for this project as defined in the Standards Authorization Request (SAR). TPL-001-2 has been approved by the industry through the standards development process and by the NERC Board of Trustees. Nothing in this project affects where footnote 12 is applied within Table 1. The only change being proposed is to the details of how to utilize footnote 12 as shown in the proposed Attachment 1.

The following clarifications to language were made due to comments received:

TPL-002-1c: footnote b) ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load.

TPL-001-2a: footnote 12 **-** An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following ~~Contingency~~ planning events.

TPL-001-2a: footnote 12 - However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1.

Organization	Yes or No	Question 1 Comment

Organization	Yes or No	Question 1 Comment
MRO NSRF USACE	No	(1) Change the wording at the end of the first sentence from "following Contingency events" to "following Contingency events and Contingency events during the planned (maintenance) outage of any bulk electric equipment)". This would remind Transmission Planners and Planning Coordinators to include the consideration of planned outages at demand levels for which the outage would be performed. (2) Raise the maximum load dropping threshold for the footnote from 75 MW to 100 MW. A 100 MW threshold is reasonable because the DOE uses the intentional dropping of more than 100 MW as one of the thresholds for determininge when enough load is dropped to justify a formal system event analysis. (3) Add a sentence at the end of the footnote to read, "This footnote does not apply to any load that is not NERC registered (e.g. load that does not meet the greater than 25 MW NERC registration criterion). (4) If a portion of the non-consequential load loss used to mitigate a contingency is controllable by a demand side load management system, can it be excluded from the "Firm Demand interruption" in TPL-002-1c Table I footnote 'b' and/or "Non-Consequential Load Loss" in TPL-001-2a Table 1 footnote 12? Does it have to be curtailed on a pre-contingent basis in order to be excluded from the non-consequential load total, or can it be excluded even if the curtailment happens through action of the UVLS? Does this load count towards the 25 MW and 75 MW thresholds? RECOMMENDATION: When describing "interruption of firm demand" or "non-consequential load loss" in footnote 'b' add the language "not counting load shed on a pre-contingent basis". This would be added to the last sentence of footnote 'b' if it indeed should not be counted towards the 75 MW threshold. Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-

Organization	Yes or No	Question 1 Comment
		2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion. (5) If multiple companies own portions of the non-consequential load loss a used to mitigate a contingency at a single substation does each company's load portion count towards the 25 MW and 75 MW thresholds or does the total load at the substation count? For example, 100% of the load at a substation is set to trip with automatic UVLS. Company A, B, and C own load amounts X, Y, and Z at the substation. Is the amount of load counted towards the 25 MW and 75 MW thresholds X+Y+Z, or is each counted separately? RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote 'b' could read "In no case can the planned Firm Demand interruption from under footnote 'b' exceed 75 MW from one entity." Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion.
Response: (1) The SDT intended the first sentence to be a fundamental statement of planning principle and thus believes that the suggested wording is redundant and therefore not required. Consideration of planned outages at demand levels for which the outage is performed is covered in proposed TPL-001-2a, Requirement R1 where it is stated that models must represent actual System conditions as well as in Requirement R2, Part 2.1.3 which clearly states that analysis is to be done when known outages are scheduled. No change made. (2) The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. DOE thresholds can be a point of reference or sanity check but in and of themselves are not sufficient for setting a threshold in this matter. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made. (3) Load that is served from the entity's transmission system is considered as applicable Load in this standard regardless of the		

Organization	Yes or No	Question 1 Comment
underlying registration situation. No change made. (4) Proposed TPL-002-1c states in the footnote that: "It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or *Demand-Side Management Load*" (emphasis added). This makes it clear that Demand-Side Management Load is not to be considered as Non-Consequential Load. In proposed TPL-001-2a, the proposed definition of Non-Consequential Load includes the term 'Interruptible Load' which as defined in the NERC Glossary includes demand to be curtailed that the end-use customer makes available through contract or agreement. Thus, the concept is covered in proposed TPL-001-2a as well. However, upon reviewing the comments, the SDT has seen that Demand that is not included as Firm Demand for footnote 'b' could be clarified as shown below. TPL-002-1c: footnote b) - ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load. (5) "Ownership" of the Non-Consequential Load Loss is not a relevant factor; all thresholds mentioned in the footnote are related to the total Non-Consequential Load Loss. No change made.		
ACES Power Marketing Standards Collaborators	No	(1) We disagree with placing an upper limit on the amount of firm load shed. Conceptually, it seems like a good idea but we do not believe that such a threshold could ever consider all of the potential issues that could arise and would cause the need to plan to shed firm load. This is especially true considering that the SAR clarifies that the upper threshold will be based on the existing planned load shedding values. Future issues cannot be considered by the information contained in the data request. Consider a situation in which a new transmission line was included in Planning Assessment but cannot be built because right of ways cannot be obtained. Should an upper limit be placed on planned load shed in such a situation? (2) We disagree with the threshold of 75 MW. In Order No. 762, the Commission discussed the "blend concept," where it "envisioned the planner would consider up to 100 MW of planned Firm Demand interruption along with other options to resolve the system performance

Organization	Yes or No	Question 1 Comment
		criteria violation and submit its documentation and explanation to the entity deciding whether the planned load shed is acceptable." (emphasis added) Even the Commission envisioned using higher thresholds. Furthermore, the data appears to show that one instance of Non-Consequential Load Loss would be immediately out of compliance because it is actual 75.2 MW not 75 MW. If the upper threshold is too close to 75 MW, any load growth might also compel the instance to be disqualified. If the SDT plans to keep the upper limit, we suggest increasing the amount to at least 100 MW.
Response: (1) The SDT understands the problematic nature of future considerations in setting threshold values. However, the SDT believes it is unrealistic to consider the allowable usage of footnote 'b' in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. No change made. (2) The SDT believes that the threshold selected is consistent with the data supplied in the data request within reasonable limits. Increasing the threshold to 100 MW is not consistent with the data supplied and the SDT believes that such an action would be viewed as a non-acceptable least common denominator approach. No change made.		
Minnkota Power Cooperative Otter Tail Power Company	No	1. MPC QUESTION: If a portion of the non-consequential load loss used to mitigate a contingency is controllable by a demand side load management system, can it be excluded from the "Firm Demand interruption" in TPL-002-1c Table I footnote 'b' and/or "Non-Consequential Load Loss" in TPL-001-2a Table 1 footnote 12? a. Would this load count towards the 25 MW and 75 MW thresholds? b. Would it have to be curtailed on a pre-contingent basis in order to be excluded from the non-consequential load total, or can it be excluded even if the curtailment happens through action of the UVLS? c. RECOMMENDATION: When describing "interruption of firm demand" or "non-consequential load loss" in footnote 'b' add the language "not counting load shed on a pre-contingent basis". This would be added to the

Organization	Yes or No	Question 1 Comment
		last sentence of footnote 'b' if it indeed should not be counted towards the 75 MW threshold. Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion. 2. MPC QUESTION: If multiple companies own portions of the non-consequential load loss used to mitigate a contingency at a single substation, does each company's load count towards the 25 MW and 75 MW thresholds or does the total load at the substation count? a. EXAMPLE: 100% of the load at a substation is set to trip with automatic UVLS. Company A, B, and C own load amounts X, Y, and Z at the substation. i. Is the amount of load counted towards the 25 MW and 75 MW thresholds X+Y+Z, or is each counted separately? b. RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote 'b' could read "In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW from one entity." Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion.

Response: (1) Proposed TPL-002-1c states in the footnote that: "It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or *Demand-Side Management Load*" (emphasis added). This makes it clear that Demand-Side Management Load is not to be considered as Non-Consequential Load. In proposed TPL-001-2a, the proposed definition of Non-Consequential Load includes the term 'Interruptible Load' which as defined in the NERC Glossary includes demand to be curtailed that the end-use customer makes available through contract or agreement. Thus, the concept is covered in proposed TPL-001-2a as well. However, upon reviewing the comments, the SDT has seen that Demand that is not included as Firm Demand for footnote 'b' could be clarified as shown below.

TPL-002-1c: footnote b) - ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm

Organization	Yes or No	Question 1 Comment
Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load. (2) "Ownership" of the Non-Consequential Load Loss is not a relevant factor; all thresholds mentioned in the footnote are related to the total Non-Consequential Load Loss. No change made.		
Iberdrola USA	No	"Contingency events" should be replaced by "Planning Events." Why would load shedding be limited only for certain circumstances in the Near-Term Transmission Planning Horizon? The Near Term is likely the period when the least can be done to avoid load shedding due to the time required for permitting and construction of facilities. A maximum capacity threshold is reasonable, whether 75 MW or a lower value.
Response: The SDT agrees that 'Contingency events' should be replaced by 'planning events' in proposed TPL-001-2a where the terminology in the performance tables uses 'planning' instead of 'Contingency'. However, such a change is not warranted in proposed TPL-002-1c where the 'planning' terminology was never used. TPL-001-2a: footnote 12 - An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following ~~Contingency~~ planning events. Footnote 'b' is not limited to the Near-Term Transmission Planning Horizon since the footnote recognizes that Firm Demand can be interrupted throughout the entire planning horizon. No change made. Thank you for your support.		
Massachusetts Attorney General	No	Although I voted for this Footnote, I do have concerns. 1) There is no reliability benefit to the 75MVA threshold limit. There should be no limit in the standard - it should be between stakeholders to decide that limit, not nationally imposed. 2) Any such agreement to consider non-consequential losses should have no impact to the BES especially when maintained in a confined boundary.

Organization	Yes or No	Question 1 Comment
		3) This takes away local decision making of PUC/ Local Board decision making; 4) FERC's concern that a few entities would disguise the "stakeholder" process to shed load is unfounded and should not be applied on a continent-wide basis. FERC is trying to impose tighter standards than the industry wants.
Response: (1) **T**he SDT believes it is unrealistic to consider the allowable usage of footnote 'b' in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. No change made. (2) The SDT agrees that it normally should not have an impact. However, the purpose of the footnote is to ensure that it will not have an impact. No change made. (3) The SDT disagrees. The PUC/Local Board would typically be part of the "applicable regulatory authorities or governing bodies responsible for retail electric service issues" shown in Attachment 1, Section I, Bullet 1. The same body would be expected to be the entity involved in Attachment 1, Section III. Therefore, the PUC/Local Board would be a primary participant in the proposed process. No change made. (4) The conditions placed on the stakeholder process will provide consistency in the application of footnote 'b' on a continent-wide basis. No change made.		
Xcel Energy	No	Although the maximum capacity value is used for planning purposes, how does this correlate with operational standards/issues that may require that value be greater. The planning studies look at very specific seasonal conditions on the system and may not necessarily look at all the states of the transmission system during the normal business day. If an operational event requiring a greater value of Non-Consequential Load Loss (NCLL) is executed and the specific outage was not considered in a planning study, how will this affect compliance with the planning standard. There was no technical rationale by the SDT for selecting the maximum value, thus a limit should not be set and should be left as a general

Organization	Yes or No	Question 1 Comment
		discussion issue in the Stakeholder Process due to the many unforeseen issues that may arise.
Response: The commenter correctly points out that this is a planning standard. Operational standards have their own sets of requirements. The proposed requirements for TPL-001-2a state that models utilized must reflect System conditions anticipated for the period in question. If the planner has done this, there should be no question as to whether they are fulfilling the requirements of the standard. No change made. The SDT believes it is unrealistic to consider the allowable usage of footnote 'b' in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. The limit selected was derived from the data received for the data request. Use of actual data is the technical rationale in the selection of the threshold. No change made.		
Electric Reliability Council of Texas, Inc.	No	As an initial matter, ERCOT does not believe the planning process should allow for nonconsequential load shedding under single contingency conditions. Accordingly, ERCOT takes no position on the proposed maximum load shedding amount. Even though the NERC BoT approved the Stakeholder Process, ERCOT does not believe that the Stakeholder Process should be included as an Attachment to a footnote to a reliability standard. Also, there is an inconsistency in the terminology used in the footnotes relative to the load shed - firm demand and non-consequential load are both used. Non-consequential load is the correct term and the language should be consistent. Although it is ERCOT's position that non-consequential load should not be allowed to be shed under single contingency conditions from a planning perspective, if the SDT elects to retain a vehicle for such exceptions, it should establish objective, reliability based criteria that lend themselves to inclusion in a reliability standard. This is consistent with the general approach for reliability standards, which prescribe the "what", not the

Organization	Yes or No	Question 1 Comment
		"how". If the exceptions are based on objective criteria that are known upfront, and those criteria reflect appropriate reliability based technical justifications, then the risk of unwarranted exceptions to the general prohibition due to misuse of the exception process is mitigated. Furthermore, the exception process should be external to the NERC Reliability Standards (e.g. in the Rules of Procedure), which should merely reference authorized exceptions granted pursuant to that process. With respect to the stakeholder process, in no case should a reliability standard mandate a stakeholder process in any respect, procedural or substantive. In ISO/RTO regions, stakeholder processes fall within ISO/RTO governance matters. These issues are beyond the purview of NERC Reliability Standards. In other regions, although the relevant functional entities do not have stakeholder processes analogous to ISOs/RTOs, any relevant processes are similarly beyond the scope of the reliability standards.Accordingly, the SDT should eliminate all revisions related to the establishment of a stakeholder process. As discussed in response to question 5, FERC is not requiring this approach, but rather has only provided guidance with respect to ways to possibly bring the prior proposal in line with applicable regulatory approval standards for reliability standards. Additionally, as a general matter, substantive reliability standards requirements should not be imbedded within a footnote to a requirement. In this case, not only is there a substantive requirement imbedded in the footnote, there is also a substantial attachment (which must become part of the enforceable standard requirements}... and, to make it worse, the attachment is an attachment to the footnote, rather than an attachment to and referred to by a reliability standard requirement.
Response: ERCOT is free to adopt a position of not allowing Non-Consequential Load shed in its reliability footprint. An entity can		

Organization	Yes or No	Question 1 Comment
always do more than the requirements stated. No change made. The SDT used the Board of Trustees approved standard as a starting point for this draft. FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. The use of footnotes and attachments is an acceptable mechanism for use in Reliability Standards and both mechanisms have been used before. No change made. The SDT believes that the terminology is consistent. Non-Consequential Load is a newly defined term that only applies to proposed TPL-001-2a. It is not appropriate to use this terminology in proposed TPL-002-1c which predates proposed TPL-001-2a. No change made. The SDT has set up criteria for consideration in the potential usage of footnote 'b' for planning purposes in Attachment 1, Section II, Bullets 1 through 8. The criteria described are objective. The process describes what must be done to allow for the usage of footnote 'b' in the planning process. No change made. The SDT used the Board of Trustees approved standard as a starting point for this draft. FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. If the ISO/RTO has an existing process that meets the requirements, it is free to use such process as stated in Attachment 1, Section I. No change made. Footnotes and attachments are acceptable mechanisms for use in Reliability Standards and both mechanisms have been used before. No change made.		
National Association of Regulatory Utility Commissioners	No	As NARUC stated plainly in its Comments filed in FERC Docket No. RM11-18 (Dec. 20, 2011), "not only does the law require that the States maintain authority over distribution level reliability, States are in the best position to guide load shedding so that it has the least negative impact on the State's customers and the operation of the local distribution system." Id at p. 4. Given the twin responsibilities of FERC to maintain bulk system reliability and the states to ensure reliable and affordable service to retail load, NARUC supports the portion of the standard that requires notification and consultation with state and local regulators. However,

Organization	Yes or No	Question 1 Comment
		the maximum capacity threshold (set at 75 MW) is problematic. In this instance, it appears that the 75 MW maximum capacity threshold is merely a reflection of antidotal information from five data request responders and as such is not technically justified. NARUC is not poised to offer an alternative; given that the state/local regulator is consulted in this process, the maximum capacity threshold should just be dropped. States should be able to authorize an 80 MW exception, or whatever level is reasonable, under specific circumstances if local economics and reliability warrant it.
Response: The data request is not anecdotal information. All of the Transmission Planners in the continental United States supplied their data in response to the data request. The SDT believes it is unrealistic to consider the allowable usage of footnote 'b' in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. Given the participation of appropriate regulatory bodies in both Sections I and III, the SDT believes that the current threshold is the best possible solution. No change made.		
American Transmission Company	No	ATC recommends the following alternative language for both Footnote 'b' (Table 1 in TPL-002-1c [page 6]) and Footnote '12' (Table 1 in TPL-001-2a [page 14]:(1) Change the wording at the end of the first sentence from "following Contingency events" to "following Contingency events for the prior condition of all equipment in service or during the planned (maintenance) outage of any bulk electric system equipment". This would remind Transmission Planners and Planning Coordinators to include the consideration of planned outages at demand levels for which the outage would be performed. (2) In the last sentence of the footnote, raise the maximum load dropping threshold for the footnote from 75 MW to 100 MW. A 100 MW threshold is reasonable because the DOE uses the intentional dropping of more than 100 MW as one of the thresholds for determining when enough load is dropped to justify a formal system event analysis.

Organization	Yes or No	Question 1 Comment
		(3) Add a sentence at the end of the footnote to read, "This footnote does not apply to any load that is not NERC registered (e.g. load that does not meet the greater than 25 MW NERC registration criterion).
Response: (1) Consideration of planned outages at demand levels for which the outage is performed is covered in proposed TPL-001-2a, Requirement R1 where it is stated that models must represent actual System conditions as well as in Requirement R2, Part 2.1.3 which states that analysis is to be done when known outages are scheduled. No change made. (2) The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. DOE thresholds can be a point of reference or sanity check but in and of themselves are not sufficient for setting a threshold in this matter. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a least common denominator approach and would thus be rejected. No change made. (3) Load that is served from the entity's transmission system is considered as applicable Load in this standard regardless of the underlying registration situation. No change made.		
Hydro QuÃ©bec TransÃ‰nergie	No	Dropping load in the general sense should not be endorsed, but it is recognized that there are special situations where it cannot be avoided. Provided there is no widespread, adverse effect on the reliability of the interconnected BES, the effect of a firm demand interruption on customers is under the purview of the applicable regulatory authority that is responsible for local transmission and retail service over the load to be curtailed, and the TPL standard should not put a limit at 75 MW.
Manitoba Hydro	No	Given that it is deemed that a stakeholder procress is required, there is no rationale for a maximum level. The stakeholders are in the best position to judge the appropriate level of allowable curtailment.
Response: The SDT believes it is unrealistic to consider the allowable usage of footnote 'b' in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. No		

Organization	Yes or No	Question 1 Comment
change made.		
Florida Municipal Power Agency Lakeland Electric Gainesville Regional Utilities	No	FMPA has two issues:1. What is the technical justification for 75 MW? There is no other metric in use similar to it. FMPA believes that, if the stakeholder process reveals that the stakeholders are willing to accept decreased service continuity to save money on their electric bills, why should that be limited to 75 MW which has nothing to do with BES reliability. BES reliability will not be impacted until load shedding gets near to the largest single loss of source contingency in relation to supply / demand mismatch. Other standards have chosen the low value of 300 MW as indicative, (e.g., CIP v5 for UFLS, EOP-004 for disturbance reporting); hence, FMPA recommends that the maximum amount of load shedding be 300 MW. 2. The footnote should also address a process whereby the transmission customer agrees to conditional firm service if the Transmission Planner / Transmission Service Provider (TSP) plans on curtailing firm service to that customer following a single contingency. The TSP should not be able to unilaterally degrade service from a state where it was not conditional to a state where it is conditional.
Response: The SDT believes it is unrealistic to consider the allowable usage of footnote ‘b’ in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote ‘b’ by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote ‘b’. Other thresholds can be a point of reference or sanity check but in and of themselves are not sufficient for setting a threshold in this matter. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made. An entity can always approach a customer to request to a change in the type of service provided, with or without the consideration of footnote ‘b’ utilization. The institution of the formal process proposed here would bring the transmission customer into the decision making process which makes any condition open and transparent and which may initiate discussions on service type as		

Organization	Yes or No	Question 1 Comment
referenced above. No change made.		
Modesto Irrigation District	No	I am voting NO because there is no technical basis for use of the 75 and 25 MW absolute threshold values, regardless of the size of the utility's load, referenced in the proposed standard. WECC's past experience with implementation of arbitrary magnitudes for requirements (e.g., the 5% and 7% arbitrary magnitude contingency reserve requirements), has proved to be problematic. I would suggest investigating a technical basis for using a relative requirement, such as percentage of the utility's load, maybe 5% and 2.5%, respectively, and that it be based on technical requirements similar to those found in Table 1 of the WECC Criteria TPL-001-WECC-CRT-2.Thank you.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. Utilizing a percentage of an entity's Load may be problematic – when dealing with a small entity it could be a small value but still of rather large import and if dealing with a large entity could result in significant amounts of Load shed being planned. The FERC Order states that a percentage approach would not be appropriate for the aforementioned reasons. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made.		
Ameren	No	It appears that a least common denominator approach was used to develop the upper limit of 75 MW. Only 1 out of 18 respondents would drop 75 MW of load, and only two respondents would drop 61-70 MW of load. Our review of the data request responses concludes that only 22% of the respondents that presently utilize footnote "b" would drop more than 50 MW, and only 33% of the respondents that use footnote "b" would drop more than 40 MW. The proposed 75 MW limit is too high and is not supported by the responses to the data request. An upper limit of 40 MW is more appropriate, based on the data responses.

Organization	Yes or No	Question 1 Comment
Response: Based on the comments received, the majority of the industry does not agree that a lower threshold would be appropriate. The SDT does not believe that a least common denominator approach was utilized. The value selected is a reasonable limit based on the data received, potential vagaries in future considerations, and undefined system configurations that may arise. No change made.		
MidAmerican Energy Company	No	MidAmerican supports NSRF comments with one change. The proposed NSRF addition of "consideration of planned outages at demand levels for which the outage would be performed" to the text of footnote "b" after "following Contingency events" should not be added. If the addition is made, a reasonable time frame clarification is necessary and should be added such as "greater than 6 months". The proposed change would then read "consideration of planned outages greater than 6 months or longer at demand levels for which the outage would be performed".
Response: The SDT is not proposing to adopt the suggested change of the MRO NSRF. Please see the response to MRO NSRF above.		
Midwest Independent Transmission System Operator, Inc.	No	No. We believe footnote b in NERC TPL 002-1 and/or footnote 12 in TPL-001-2 should be eliminated because the intent of these standards is not to rely on non-consequential firm load shedding after a single contingency event. However, if these footnotes are not eliminated, there should be some limitation on how much firm load shed is allowed. We object to any level higher than the proposed 75 MW level and would prefer a level below 75 MW, but won't object to the proposed 75 MW level if the footnotes are not eliminated.
Response: The SDT believes that the wording of the footnote states that Non-Consequential Load shedding should not be the intent but recognizes that particular circumstances may result in such a planned action. The 75 MW level is being retained. No change made.		
Duke Energy	No	Regarding the maximum capacity item, we believe that 75 MW is much too low. While Duke Energy has not historically used the footnote, setting

Organization	Yes or No	Question 1 Comment
		the upper limit at 75 MW raises a concern. An upper limit of 75 MW severely limits the ability of a Transmission Planner to use the footnote. The 75 MW limit appears to be the maximum reported in the survey. The survey is a snapshot in time and to assume that there never have been nor never will be situations where the correct decision of a Transmission Planner and its stakeholders would be to exceed the 75 MW limit is illogical. The 75 MW limit is likely to create a situation where a Transmission Planner is forced to convert a network line to radial in order to remain in compliance with the standard, to the detriment of reliability to customers. The key to understanding use of the footnote is realizing that, in most cases, using the footnote is extremely unlikely to result in customer outages, because the probablility of the initiating contingency occurring under conditions requiring additional load shed is very low. A more reasonable upper limit would be the 300 MW limit that is established as the threshold for DOE Disturbance Reporting. It is also important to remember that no matter what upper limit is established, Non-consequential Load Loss of 25 MW or greater cannot be included in Year One of the Planning Assessment if the applicable regulatory authority or governing body responsible for retail electric service issues objects.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. DOE thresholds can be a point of reference or sanity check but in and of themselves are not sufficient for setting a threshold in this matter. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made.		
Southern California Edison Company	No	SCE believes that the maximum capacity threshold should be increased from 75 MW to 250 MW, as 250 MW is the limit utilized by the California Independent System Operator (CAISO) for a consequential load drop for a single contingency. The CAISO has a rigorous transmission planning

Organization	Yes or No	Question 1 Comment
		process that allows it to plan for and permit load shedding up to 250 MW.
Response: The footnote only applies to Non-Consequential Load Loss. Upon reviewing the comments, the SDT has seen that Demand that is not included as Firm Demand for footnote ‘b’ could be clarified as shown below. TPL-002-1c: footnote b) - ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load.		
Arizona Public Service Company	No	The 75 MW threshold is too low. No technical justification has been given for choosing 75 MW. It should be a significantly higher value for TPL-002. Currently AZPS does not use non-consequential load dropping to meet any standard but this option should be preserved. There could be times when alternate to the load dropping would be building a new transmission line costing hundreds of millions of dollar for a very low probability scenario of high load conditions. The threshold value should be 100 MW or more.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote ‘b’ by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote ‘b’. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made.		
Northeast Power Coordinating Council	No	The 75MW of Firm Demand interruption is retail load that is being dropped. Dropping load in the general sense should not be endorsed, but it is recogn ized that there are special situations where it cannot be avoided. If a regulator responsible for retail load is comfortable with greater than 75MW being dropped in a rare situation, there should not be a requirement to build out of the situation. Provided there is no widespread, adverse effect on the reliability of the interconnected BES, the effect of a firm demand interruption on customers is under the purview of the applicable regulatory authority that is responsible for local

Organization	Yes or No	Question 1 Comment
		transmission and retail service over the load to be curtailed. There is no technical basis for the 75MW figure. It was included as a result of a Section 1600 Data Request, and is an arbitrary value. There should not be a limit without a technically supportable reliability based reason.
National Grid	No	The 75MW of Firm Demand interruption is retail load that is being dropped. Dropping load in the general sense should not be endorsed, but it is recognized that there are special situations where it cannot be avoided. If a regulator responsible for retail load is comfortable with greater than 75MW being dropped in a rare situation, there should not be a requirement to build out of the situation. Provided there is no widespread, adverse effect on the reliability of the interconnected BES, the effect of a firm demand interruption on customers is under the purview of the applicable regulatory authority that is responsible for local transmission and retail service over the load to be curtailed. There is no technical basis for the 75 MW figure with respect to reliability impact. Although, the value was developed by the SDT as a result of their review of Section 1600 Data Request, there was no reliability based analysis performed to identify whether the 75 MW is reasonable number. It is possible that a number either larger or lower could be identified if a reliability and cost-effective analysis is conducted.
Response: The SDT believes it is unrealistic to consider the allowable usage of footnote ‘b’ in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. No change made. The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote ‘b’ by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote ‘b’. All of the Transmission Planners in the continental United States supplied their data in response to the data request. The SDT believes that any deviation from the threshold derived from the actual		

Organization	Yes or No	Question 1 Comment
data may be viewed as a non-acceptable least common denominator approach. No change made.		
ISO New England	No	The draft footnote states that interruption "is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1." Attachment 1 appears to impermissibly require State participation in federal transmission planning processes. Further, it places the ERO in a Transmission Planning role, which exceeds the limits of the ERO's functions under Section 215 of the Federal Power Act. The current language appears to conflict with (1) federal statutes that are clear that wholesale electric transmission issues are matters of federal, and not state, jurisdiction, (2) orders of the Federal Energy Regulatory Commission ("FERC") regarding the role and independence Regional Transmission Organizations ("RTOs") with regard to transmission planning, and (3) Section 215 which limits NERC's authority to regulate "users, owners and operators" of the Bulk-Electric System. Further, the conditions appear to conflict with Section 215 of the Federal Power Act by placing the ERO in a transmission planning role and providing it with regulatory or functional oversight regarding the substance of transmission planning decisions. The ERO has the authority to develop and enforce standards, but is not a transmission planning entity and does not have the authority to substitute its judgment for registered Planning Authorities and Transmission Planners regarding the planning or operation of the bulk power system. Where a review is sought of planning entities' determinations, per FERC-filed Tariffs, they may be brought before FERC under Section 206 of the Federal Power Act. Because the footnote, and the associated Attachment appear to be in conflict with FERC Tariff and other statutory provisions, they should be removed. The footnote itself states, "An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events." The objective statement within the

Organization	Yes or No	Question 1 Comment
		standard does not appear to create a requirement and should be removed.
Response: The SDT does not believe that the footnote violates any regulations concerning transmission planning since there is no federal process as cited in the comment. The proposed process simply brings stakeholders, including local regulators, to the table in an open and transparent manner while setting criteria for when footnote 'b' can potentially be utilized. The ERO is not participating in the planning process. The role of the ERO is restricted to a determination of whether the planned utilization of footnote 'b' will cause an Adverse Reliability Impact to the BES. The ERO has no further role in the transmission planning process beyond that determination. No change made. The SDT believes that the objective statement referenced is an important consideration in the over-all planning process and thus should be retained. It sets the over-all tone and approach that should be followed. No change made.		
Deseret Generation & Transmission	No	The limitation of Non-Consequential load loss to the 25 MW-75 MW level with a hard limit at 75 MW is arbitrary and give no deference to the cost of the cure. In the West the high cost of a fix may not be in the public interest. The 75 MW hard high limit should be replaced with a soft 75 MW limit but allowing higher levels if the governing body or regulatory authority approves it.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. The SDT believes it is unrealistic to consider the allowable usage of footnote 'b' in the planning process without a hard cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. No change made.		
New England States Committee on Electricity (NESCOE)	No	The New England States Committee on Electricity (NESCOE) appreciates the opportunity to comment on NERC's proposed revisions to Transmission Planning (TPL) Reliability Standards relating to permissible applications of planned load interruption. NESCOE is New England's Regional State Committee and is governed by a board appointed by the

Organization	Yes or No	Question 1 Comment
		six New England Governors. These comments reflect the collective view of the six New England states.The issue of planned, limited load interruption rests at the central intersection of cost and reliability. It illustrates the fundamental balance that Commissioner Norris details in Order No. 762: the tradeoffs between “increasing levels of reliability and the costs that come along with achieving them.” Transmission Planning Reliability Standards, Order No. 762, 139 FERC Â¶ 61,060 (April 19, 2012) (Norris, Comm’r. concurring in part and dissenting in part) at 2. NESCOE agrees with Commissioner Norris that, as a general matter, this balancing should translate to a more explicit consideration of costs in the NERC standard development process. Id. at 1. The language in footnote “b”- and corresponding footnote 12 of TPL-001-2-implicitly recognizes cost considerations in transmission planning by tolerating limited load shedding under defined circumstances. NESCOE offers below comments and suggestions in response to the SDT’s questions. These responses reflect NESCOE’s interest in planning for a robust bulk electric system while taking into account the magnitude of risk that a solution is intended to address and the costs associated with competing solutions. NESCOE appreciates the work of the SDT in attempting to respond to the Commission’s directives and the time constraints under which the SDT was required to make changes to footnote “b.” However, NESCOE is concerned that establishing a bright-line maximum capacity threshold that is an absolute ceiling is overly prescriptive and unnecessary to meet the Commission’s directives. In Order 762, the Commission rejected the contention that regional stakeholder processes should unilaterally determine the appropriate criteria to apply in planning to interrupt firm load. Order 762 at P 32. However, provided that technical parameters are in place, the Commission stated that it would be “amenable” to regional stakeholders establishing such criteria if, for example, NERC or the applicable Regional Entity “developed an exception process that

Organization	Yes or No	Question 1 Comment
		provides flexibility in decisions based" on their expert view of regional considerations. Id. The SDT's proposal, however, would impose a one-size-fits-all requirement that forecloses a regional discussion of the quantitative and qualitative considerations that may justify an exception to the proposed 75 MW maximum capacity value. Such a regional discussion in ongoing in New England. In 2010, ISO New England introduced to stakeholders a draft Transmission Planning Load Interruption Guideline. The Guideline noted that load interruption should not be the principal tool to address transmission system reliability violations and highlighted the priority of reliable service. However, applying quantitative and qualitative criteria, the Guideline proposed for stakeholder discussion various levels of controlled load interruption in N-1-1 conditions-potentially up to hundreds of megawatts-that may be tolerated under clearly defined conditions. NESCOE did not take a view of the Guideline when it was presented for review and does not do so here. For now, the Guideline remains in draft form following stakeholder comment in 2011. However, imposition of a maximum capacity threshold that is an absolute ceiling for N-1 events and potentially, through revisions to footnote 12, N-1-1 events, would prematurely limit important regional discussions of this issue. A better approach, and one which the Commission appears amenable, would be to accompany any bright-line value with an exception process. There is recent precedent supporting such an approach: NERC proposed changes to its Rules of Procedure to accommodate exceptions to the proposed 100 kV bright-line Bulk Electric System definition. Separately, the footnote references Attachment 1 to the respective planning standards, which requires a stakeholder process review of the utilization of planned interruption. Such review is only triggered if utilization is sought in the Near-Term Transmission Planning Horizon, even though the footnote permits utilization of load interruption throughout

Organization	Yes or No	Question 1 Comment
		the planning horizon. NESCOE does not support this limiting language, which is at tension with an open and transparent planning process over the entire planning horizon. The term “Near-Term” should be stricken or further justification should be provided.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote ‘b’ by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote ‘b’. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. The SDT believes it is unrealistic to consider the allowable usage of footnote ‘b’ in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. The SDT believes that the referenced exception process is what is being proposed. The proposed process sets up an open and transparent process for allowing such Load shed in specific conditions and with specific limitations. Any future revisions to footnote 12 will be accomplished through the approved standards development process and any discussion on changing threshold values would be part of that process. No change made. Footnote ‘b’ is not limited to the Near-Term Transmission Planning Horizon since the footnote recognizes that Firm Demand can be interrupted throughout the entire planning horizon. As drafted, the standard defines the stakeholder process as mandatory for the Near-Term Transmission Planning Horizon since there may not be time to implement other corrective actions but does not limit its use in the Long-Term Transmission Planning Horizon. How individual entities reflect the Long-Term Transmission Planning Horizon situations in its individual stakeholder processes is left to the entity to determine. No change made.		
Sacramento Municipal Utility District	No	There is no reliability benefit with an establish MW threshold. Implementing any threshold is descriptive and the standard should depict an outcome not the means of the outcome.
Response: The SDT believes it is unrealistic to consider the allowable usage of footnote ‘b’ in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. No change made.		
Public Utility District No.1 of Snohomish	No	We believe the survey significantly underestimated the use of Non-Consequential Load Shedding because the survey asked about past usage

Organization	Yes or No	Question 1 Comment
County Tacoma Power MEAG Power City of Austin Clark Public Utilities		of footnote b under Version 001, not about planned load shedding in TPL version 002 or the proposed footnote 12. TPL version 002 added several new contingencies, and also changed the Non Consequential Load shedding applicability for several contingencies. We have 4 specific concerns, followed by several suggested edits: 1) Analyzing the contingencies “P1.4 Loss of a Shunt Device” and “P2.1 Opening of a line section w/o a fault” are new requirements that will lead to increased use of footnote 12. It is common on fringes of the interconnected system to have weak sources. Significant utility investment will be redirected to remediate these fringe performance issues due to the P2.1 and its associated restrictions for firm load shedding and no RAS or UVLS mitigation. This is a low probability and low impact to the main grid contingency with a high mitigation cost, given the new mitigation restrictions. 2) Contingencies “P2.2 Bus Section fault” and “P2.3 Internal Breaker Fault” were previously defined as category “C multiple contingencies” with the restriction that the Firm Load shedding must be planned/controlled. However Version 002 no longer allows dropping nonconsequential load for EHV but removes all restrictions for HV load shedding. Since these contingencies result in opening the same breakers as category P1 contingencies, the use of footnote 12 should be consistent with P1. 3) Contingencies P3.1-P3.4 were previously defined as category “C multiple contingencies” with Firm loading shedding allowed. In version 2, these contingencies have been changed from allowing planned load shedding to only allowing Non-Consequential load shedding per footnote 12. Although this does not directly impact our utility, the survey results do not include utilities using “must-run” generation. 4) As demonstrated by multiple questions at the last webinar, many

Organization	Yes or No	Question 1 Comment
		utilities do not understand the definition of Non-Consequential Loads, and therefore may not have correctly reported the usage of Non-Consequential Load Shedding. The v2 changes cascade to the unfortunate conclusion that UVLS and RAS are no longer permitted as cost effective transmission performance mitigation, despite new low probability contingencies that drive performance problems at the edges of the network. -Proposed changes: A) Change the maximum amount from 75 MW to 300 MW. Several other standards including CIP have a strong technical basis for selecting 300 MW as the maximum limit for load shedding programs. B) Footnote 12 on contingency 2.1 should be replaced with a new footnote 15 that reads " 15. For this contingency, load which is served radial from a remaining single source line may be shed as if it were Consequential Load." This change would acknowledge that while P2.1 does involve just one element, the likelihood of occurrence is similar to bus section faults, so the resulting system performance requirements should be similar. C) The first two sentences of footnote 12 should be deleted. Remove the first sentence because it is general in nature and is a basic tenant of any load-serving utility. Remove the second sentence because column 7 of Table 1 explicitly states where Non-Consequential Load Loss is allowed. D) The third sentence of footnote 12 should have the words "under footnote 12" added. Without this addition, all Non Consequential Load Loss including the allowed loss for P4, P5 and P6 would still be subject to Appendix 1. The revised sentence would read "When Non-Consequential Load Loss is used under footnote 12 within the Near-Term ..."
Response: The SDT could not reasonably request data for unknown future conditions. The only viable mechanism for data input was the data request as it was formulated.		

Organization	Yes or No	Question 1 Comment
1) The SDT disagrees that planning events P1.4 and P2.1 are 'new' requirements in proposed TPL-001-2a. These requirements were previously approved by the industry and NERC Board of Trustees. No change made. **2)** The SDT disagrees that P2.2 and P2.3 planning events will open the same breakers as P1 planning events. For the EHV planning events cited, the standard approved by the industry and the NERC Board of Trustees accepted a raising of the bar by not allowing Non-Consequential Load Loss for these events. This posting of proposed TPL-001-2a does not change the application of the footnote. No change made. **3)** For the P3.1 – P3.4 planning events, the standard approved by the industry and the NERC Board of Trustees accepted a raising of the bar by not allowing Non-Consequential Load Loss for these events. This posting of proposed TPL-001-2a does not change the application of the footnote. No change made. **4)** Discussion of the proposed definition of Non-Consequential Load was provided during the various postings of proposed TPL-001-2. The SDT has received no comments from other utilities regarding confusion over the definition. Single Contingencies are not low probability events. No change made. A) The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. DOE thresholds such as the 300 MW referenced above can be a point of reference or sanity check but in and of themselves are not sufficient for setting a threshold in this matter. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made. B) For planning event P2.1, the standard approved by the industry and the NERC Board of Trustees accepted a raising of the bar by not allowing Non-Consequential Load Loss for these events. This posting of proposed TPL-001-2a does not change the application of the footnote. No change made. C) The SDT believes that such statements are important to set the tone and approach to be taken with the planning standards. No change made. D) The SDT agrees and has made the suggested clarification. TPL-001-2a: footnote 12 - However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1.		
Independent Electricity System Operator	No	We disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard. Provided there is

Organization	Yes or No	Question 1 Comment
		no adverse effect on the reliability of the interconnected bulk power system, the effect on customers of a firm demand interruption is the responsibility of the applicable regulatory authority or its agencies responsible for local transmission and retail service over the load to be curtailed.We propose replacing the sentence, in the footnote and in attachment one, section III that reads:"In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW." with "In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss under footnote 12 for a Registered Entity that is a Canadian Entity (or a Mexican Entity) should be implemented in a manner that is consistent with/or under the direction of the Applicable Governmental Authority or its agency in Canada (or Mexico).
Hydro One Networks Inc.	No	We disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard. Provided there is no widespread, adverse effect on the reliability of the interconnected bulk electric system, the effect on customers of a firm demand interruption is the responsibility of the applicable regulatory authority or its delegated agencies responsible for local transmission and retail service over the load to be curtailed.If it is decided to proceed with the 75 MW or any other value, we propose replacing the sentence, in the footnote and in attachment one, section III that reads:"In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW." with "In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss under footnote 12 for a non-US Registered Entity should be determined by the applicable Regulatory Authority or Governmental Authority or its delegated agency in that is responsible for retail electric service issues in that jurisdiction."

Organization	Yes or No	Question 1 Comment
Response: Canadian entities are allowed to adopt ERO Reliability Standards, reject them outright, or adapt them for their own use within the confines of provincial regulations. Nothing has changed in that regard with this proposed standard. The effective date language covers the situation. No change made.		
NB Power Transmission	No	We disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard. Provided there is no widespread, adverse effect on the reliability of the interconnected bulk electric system, the effect on customers of a firm demand interruption is the responsibility of the applicable regulatory authority or its delegated agencies responsible for local transmission and retail service over the load to be curtailed.
NBSO	No	We do not agree with setting a MW limit for non-consequential load loss. The allowable amount should be determined and approved by the jurisdiction of the area(s) whose load is affected. The intent of the TPL standard and this footnote is to ensure that if non-sequential load loss is accounted for or relied up to ensure BES reliability (as assessed in the planning horizon), that such a decision needs to be approved by the appropriate jurisdiction. Non-consequential load loss being applied or considered to achieve BES reliability in planning assessment is in itself not a BES reliability concern that rises up to a continent-wide reliability standard.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. DOE thresholds such as 300 MW can be a point of reference or sanity check but in and of themselves are not sufficient for setting a threshold in this matter. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made.		

Organization	Yes or No	Question 1 Comment
Western Area Power Administration	No	We do not support a maximum threshold of 75 MW or any MW level. It is not appropriate to enforce a one size fits all maximum value. There are no apparent reliability benefits from implementing a capacity loss limitation...why not pick 300 MW? Also we are not sure what prompted the additional distinction of allowing the load shedding only in the near-term planning horizon...please elaborate.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote ‘b’ by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote ‘b’. DOE thresholds such as 300 MW can be a point of reference or sanity check but in and of themselves are not sufficient for setting a threshold in this matter. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made. Footnote ‘b’ is not limited to the Near-Term Transmission Planning Horizon since the footnote recognizes that Firm Demand can be interrupted throughout the entire planning horizon. No change made.		
Platte River Power Authority	No	We do not support a maximum threshold. 1) It is not appropriate to enforce a one size fits all maximum value that might unnecessarily over-burden some communities. 2) The public process proposed in this standard provides significant transparency from the transmission utilities and opportunity for community input to decisions that will impact both the community's reliability and rates. 3) Leave the maximum capacity threshold decisions to local regulatory commissions and Boards of Directors.
Response: (1) The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote ‘b’ by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value		

Organization	Yes or No	Question 1 Comment
for the amount of Load that could be planned to be shed under footnote ‘b’. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made. (2) Thank you for your support. (3) The SDT believes it is unrealistic to consider the allowable usage of footnote ‘b’ in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. Local regulators are involved in the process through the wording in Attachment 1, Sections I and III. No change made.		
California Independent System Operator	No	While we have voted in favor of supporting the changes to the footnote and to move forward with the adoption of the standard, we remain concerned that there is not a good foundation for concluding that loss of load over 75 MW poses a reliability risk to the system compared to some higher MW threshold. Instead, the 75 MW capacity threshold is simply based on the current maximum planned loss of Non-Consequential Load. While we support minimizing reliance on Non-Consequential Load Loss, there may be scenarios where such reliance is unavoidable in the near-term, and therefore may be needed until capital upgrades can be put in place. At a minimum, the footnote or standard should provide for an exception process, should it be necessary for a planned Non-Consequential Load Loss of greater than 75 MW.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote ‘b’ by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote ‘b’. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. The SDT believes that the referenced exception process is what is being proposed. The proposed process sets up an open and transparent process for allowing such Load shed in specific conditions and with specific limitations. No change made.		
Tri-State Generation & Transmission Association	No	

Organization	Yes or No	Question 1 Comment
LCRA Transmission Service Corporation	No	
Response: Without a specific comment, the SDT is unable to respond.		
TVA Transmission Reliability Engineering and Controls	Yes	TVA agrees with the general text; however, TVA believes that the 75 MW limit is too low. TVA believes that a better limit would be 100 MW - which is the amount for load shedding required to be reported under OE-417 under emergency operational policy. This would allow some future load growth as well as any possible new loads that may develop quickly in which a utility may not have time to complete necessary projects in a corrective action plan.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. DOE thresholds can be a point of reference or sanity check but in and of themselves are not sufficient for setting a threshold in this matter. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made.		
Southwest Power Pool Reliability Standards Development Team	Yes	
Bonneville Power Administration	Yes	
SERC EC Planning Standards Subcommittee Associated Electric Cooperative, Inc.	Yes	
Southern Company	Yes	
American Electric Power	Yes	
Seminole Electric Cooperative, Inc.	Yes	

Organization	Yes or No	Question 1 Comment
Public Service Company of New Mexico	Yes	
Idaho Power Company	Yes	
SCE&G	Yes	
Lincoln Electric System	Yes	
Georgia Transmission Corp	Yes	
Response: Thank you for your support.		

2. **Do you agree with the description and components of the Stakeholder Process in Section I of Attachment 1? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: There was little or no commonality in the comments submitted and the responses are mainly statements clarifying SDT intent as shown in the individual responses.

The following change was made due to industry comment:

TPL-002-1c: footnote b) - ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load.

Organization	Yes or No	Question 2 Comment
Southern Company	No	The complex stakeholder process described in Attachment 1 should be required only if the amount of planned load shed exceeds 25 MW or the contingency is greater than 300 kV. Since the average use given in the survey was 19 MW and there is no evidence of harm to the BES reliability resulting from that use, there is no good reason to require such a stakeholder process for amounts less than 25 MW. The stakeholder process should only be required for larger amounts of load.
SCE&G	No	No, We recommend that up to 25 MW of planned interruption be allowed without triggering the need for a stakeholder process. Since the average use given in the survey was 19 MW and there is no evidence of harm to the BES reliability resulting from that use, there is no reason to require a stakeholder process for amounts less than 25 MW. This is consistent with the value cited in Section III.
TVA Transmission Reliability Engineering and Controls	No	TVA recommends that up to 25 MW of planned interruption be allowed without triggering the need for a stakeholder process. Since the average use given in the survey was 19 MW and there is no evidence of harm to the BES reliability resulting

Organization	Yes or No	Question 2 Comment
		from that use, there is no reason to require a stakeholder process for amounts less than 25 MW. This is consistent with the value cited in Section III.
SERC EC Planning Standards Subcommittee Associated Electric Cooperative	No	We recommend that up to 25 MW of planned interruption be allowed without triggering the need for a stakeholder process. Since the average use given in the survey was 19 MW and there is no evidence of harm to the BES reliability resulting from that use, there is no reason to require a stakeholder process for amounts less than 25 MW. This is consistent with the value cited in Section III.
Response: The SDT disagrees that the proposed process is complex or unnecessary. The SDT used the Board of Trustees approved standard as a starting point for this draft. FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. The SDT believes that all uses of footnote 'b' should go through the stakeholder process. No change made.		
Seminole Electric Cooperative, Inc.	No	#1.It is unclear what factors must be met in order to be an affected stakeholder under the Stakeholder Process in Attachment 1? This process appears to be devoid of any objective factors that can assist an entity in determining whether a party is a stakeholder or not. NERC should define what an "affected stakeholder" is or list factors to assist industry in making such a determination. #2.In Standard TPL-002-1c, Attachment 1, Section I. "Stakeholder Process," there was a section added at the end of this subsection that is three lines in length. This section states that a stakeholder process does not need to be repeated unless there has been a "material change." It is clear from the latest webinar presentation on this Project that this language is not "clear and unambiguous". NERC does not present any metrics, whether qualitative or quantitative, to guide industry as to when a material change occurs to an application of footnote 'b.' Without any metrics to guide industry, it is bewildering that NERC reasons that entities will consistently interpret what a material change constitutes. Therefore, SECI believes that this provision is in conflict with the NERC Rules of Procedure and FERC Order

Organization	Yes or No	Question 2 Comment
		762. #3.In Standard TPL-002-1c, Attachment 1, Section I. “Stakeholder Process,” the requirement that the process “shall be documented” was deleted from the first paragraph. It does not appear to be reasonable that a process that is not written, nor known to any stakeholder, meets the common understanding of “open and transparent.” Seminole believes that the requirement that the process be documented and that documents be available to potential affected parties be reinstated into the Standard.
Response: 1. The SDT believes that the planning entity is in the best position to identify affected stakeholders and that any attempt to codify a list of such stakeholders in the proposed standards could lead to errors due to the necessity of having to adopt a one size fits all approach. No change made. 2. The SDT believes that the planning entity has the best understanding of when a change would become material. With the large range of design philosophies and geographic difference between the entities within NERC, it is not practical to adopt a single one size fits all approach. In addition, since the use of footnote ‘b’ will be a part of the entity’s Corrective Action Plans, interested stakeholders will have the opportunity to question the continued use of footnote ‘b’. No change made. 3. The SDT believes the ‘documented’ terminology is unnecessarily redundant since the entity must be able to demonstrate compliance to its Compliance Enforcement Authority. It should not be necessary to mandate that an entity has to document a process. No change made.		
NBSO	No	(1) The process presented in Section I of Attachment I is overly prescriptive. This Section needs only to stipulate that the proposed utilization of the footnote be reviewed through an open and transparent stakeholder process developed and/or approved by the jurisdiction (a Regional Entity or regulatory authority) of the area(s) whose load is affected area. (2) There is no basis to support allowing the utilization of the footnote in the Near-Term Transmission Planning Horizon of the Planning Assessment only. The footnote itself should not explicitly restrict its utilization to only the Near-Term horizon. Often, in the long-term planning horizon, when approval for transmission addition

Organization	Yes or No	Question 2 Comment
		or reinforcement cannot be obtained for whatever reasons, utilization of the footnote is considered and adopted, subject to stakeholder's and regulatory authority's approvals. Note that it is impractical to add or reinforce transmission facilities in a near-term planning (e.g. Year One) time frame and hence the proposed provision does not allow for utilizing the footnote for the interim period before new or reinforced transmission facilities are put in place. We suggest removing the word "Near-Term".
Response: (1) FERC remanded the standard because they wanted the stakeholder process better defined, including a blend of quantitative and qualitative criteria for allowing curtailment of Firm Demand and assurance that BES reliability would be maintained. The balloted draft added the indicated detail and specificity to the already approved approach. No change made. (2) Footnote 'b' is not limited to the Near-Term Transmission Planning Horizon since the footnote recognizes that Firm Demand can be interrupted throughout the entire planning horizon. As drafted, the standard defines the stakeholder process as mandatory for the Near-Term Transmission Planning Horizon since there may not be time to implement other corrective actions but does not limit its use in the Long-Term Transmission Planning Horizon. How individual entities reflect the Long-Term Transmission Planning Horizon situations in its individual stakeholder process is left to the entity to determine. No change made.		
ACES Power Marketing Standards Collaborators	No	(1) Many RTOs have well organized stakeholder processes that could be utilized to satisfy Attachment 1. Because the TPL standards apply to both the PC and TP, one may conclude that both functions need to have a stakeholder process. Rather, we think that the TP should be able to rely on its PC's stakeholder process. We recommend clarifying Attachment 1 that it is acceptable for the TP to rely on the PC's process and that both entities are not required to have redundant processes. The most important point is that stakeholders have an opportunity to participate.
Response: The SDT believes that it has covered this possibility in the revised language posted for this draft allowing an entity to use an existing process as long as it meets the criteria. Such usage is not restricted to a particular entity and as long as each entity is able to demonstrate that it meets the items in Section I, entities can share the same process. No change made.		
Minnkota Power Cooperative	No	1. MPC QUESTION: In Attachment 1 Section I, what is the definition of a

Organization	Yes or No	Question 2 Comment
Otter Tail Power Company		"stakeholder"? a. Is this intended to apply to multiple NERC functional entities (DP, TO, TOP, LSE), public residential customers, and/or business owners that are affected by system contingencies? b. RECOMMENDATION: Define stakeholder to be "affected Transmission Owners, Transmission Operators, Distribution Providers, and Load-Serving Entities." We believe it is most appropriate for the Transmission Owners, Transmission Operators, Distribution Providers, and Load-Serving Entities to objectively evaluate the risks of load shedding in a local area against the cost impact of a large transmission project on the rate base. 2. MPC QUESTION: In Attachment 1 Section I item 1, what does "including applicable regulatory authorities" refer to? a. Is this the same body that "applicable regulatory authority or governing body" refers to in Section III? b. Are these requirements still applicable if the 25 MW threshold in Section III is not passed? c. RECOMMENDATION: Attachment 1 Section I Item 1 could read "... including applicable regulatory authorities or governing bodies responsible for retail electric service as described in Section III. A clearly defined statement allows the Transmission Planner and Planning Coordinator to identify the appropriate parties to be included in every instance Attachment 1 is used.
Response: 1. The SDT believes that affected stakeholders should include the list of NERC functional entities and others. Transmission customers, Planning Coordinators, Transmission Planners, and regulatory authorities with retail jurisdiction should typically be included. The SDT believes that the planning entity has the best understanding of who an affected stakeholder will be and that any attempt to codify a list of such stakeholders in the proposed standards could lead to errors due to the necessity of having to adopt a one size fits all approach. No change made.		

Organization	Yes or No	Question 2 Comment
2. a. Yes, it is the same as those in Section III. b. Yes, these requirements are applicable for each circumstance of planned use of footnote b. The SDT believes that the use of the stakeholder process is necessary each time that an entity utilizes footnote b. c. The SDT did not accept your recommendation. The SDT believes that the suggested change may be too limiting since it refers to a single governing body. No change made.		
Western Area Power Administration	No	A public process seems out of place in a reliability standard.
Response: FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. No change made.		
Manitoba Hydro	No	A stakeholder process should not be required in jurisdictions where a legislation already authorizes interruptions, as consent of stakeholders cannot override legislation.
Response: The SDT does not believe that the consent of stakeholders will override legislation. The proposed process provides an opportunity for affected stakeholders, including regulators, to have the necessary information to fully understand the impacts of the planned use of footnote b. If the applicable regulator does not object to the planned use of footnote b, it may be used. No change made.		
Iberdrola USA	No	“Stakeholders” is undefined - would this be the same stakeholder body identified in the planning process of the Open Access Transmission Tariff?
Response: In many instances, the affected stakeholders would be the same stakeholders identified in the Open Access Transmission Tariff planning process. However, the SDT believes that the planning entity has the best understanding of who an affected stakeholder will be and that any attempt to codify a list of such stakeholders in the proposed standards could lead to errors due to the necessity of having to adopt a one size fits all approach. No change made.		

Organization	Yes or No	Question 2 Comment
Public Utility District No.1 of Snohomish County MEAG Power City of Austin Clark Public Utilities Tacoma Power	No	In the first sentence, remove the words “as an element of a Corrective Action Plan.” There are cases on the fringes of the system where Non-Consequential Load Loss is the preferred alternative in both the long term and short term, not as a temporary patch. Requiring the stakeholder process as part of Corrective Action Plan implies that using footnote 12 cannot be the long term choice. Since a Corrective Action Plan is a “list of actions and an associated timetable for implementation to remedy a specific problem,” using this term removes the stakeholders ability to evaluated the costs and benefits and instead requires them to treat this a problem where the only solution is building new facilities.
Response: The stakeholder process is not required as part of a Corrective Plan. What the attachment states is that use of the footnote cannot be part of the Corrective Action Plan unless it has gone through the process. And the SDT disagrees that inclusion of this language ever requires a construction solution. Bullet #7 in Section II requires that alternatives to Load shed be presented for process participants to see as well as providing the rationale for not selecting those alternatives. Cost and benefits can certainly be part of this rationale. No change made.		
Ameren	No	It is our opinion that that the stakeholder process should be conducted at least once every five years if non-consequential load is planned to be dropped as part of the Corrective Action Plan to meet single contingency events. If conditions have not materially changed since the last review, this information should still be communicated to the stakeholders.
Response: The SDT did not want to present repetitive information and unduly burden the planning entity or the stakeholder in this process. However, an entity can always do more than what is required in the standard. No change made.		
Tri-State Generation & Transmission Association	No	NERC Functional Model definitions for Planning Authorities and Transmission Planners do not include the types of activities being proposed in “Attachment 1.” How is it appropriate to mandate to functional entities functions that are outside those defined in the NERC functional model?
Response: The NERC Functional Model is a guideline for activities required of cited functional entities. It is periodically updated as		

Organization	Yes or No	Question 2 Comment
conditions change. While the activities mentioned in the standard may not be explicitly spelled out in the NERC Functional Model, the SDT does not believe that they are out of scope for either a Planning Coordinator or a Transmission Planner. No change made.		
New England States Committee on Electricity (NESCOE)	No	NESCOE appreciates the efforts of the SDT in developing a stakeholder process for considering the use of load interruption in system planning. NESCOE especially appreciates the heightened role accorded to states in light of jurisdictional issues raised by the prospect of shedding load and implications for retail customers. States must be intimately involved in weighing reliability considerations against the economic implications of alternative approaches. Regarding the language in Section I, see the comments above regarding striking "Near-Term" in this context. NESCOE also suggests that additional clarity is needed regarding the intended meaning of "applicable regulatory authorities or governing bodies responsible for retail electric service issues." This language potentially implicates state agencies beyond public utility commissions (e.g., state consumer advocates, attorneys general) and could create confusion for state agencies as well as transmission planners that are required to provide notice to such entities and, pursuant to Section III, provide a process for regulatory review. Instead, the SDT should revise the language to read "electric retail regulatory authorities," a term with clear meaning that the Commission has itself used. See, e.g., Order 719.
Response: Please see the response to question 1. The SDT believes that there may be instances where other regulatory bodies may want to be involved in the stakeholder process. The SDT disagrees that the proposed language will create confusion for state agencies or transmission planners. The SDT believes that the planning entity has the best understanding of who an affected stakeholder will be and that any attempt to codify a list of such stakeholders in the proposed standards could lead to errors due to the necessity of having to adopt a one size fits all approach. No change made.		
Independent Electricity System Operator	No	No. The process presented in Section I is overly prescriptive. If a section that prescribes the principles of a stakeholder process is required, then for Canadian entities this section should simply state that any threshold should be established in

Organization	Yes or No	Question 2 Comment
		a manner consistent with other service levels that apply to local transmission and retail service for the load to be curtailed. Corrective action plans can rarely be implemented in a one-year time frame, and in some cases, limited use of Non-consequential Load Loss will be preferable to unaffordable transmission enhancements, therefore we believe that the use of footnote 'b'/'12' should not be limited to the Near-Term Transmission Planning Horizon. We propose that the phrase "the Near-Term Transmission Planning Horizon of" be deleted from the opening paragraph.
Response: Canadian entities are allowed to adopt ERO Reliability Standards, reject them outright, or adapt them for their own use within the confines of provincial regulations. Nothing has changed in that regard with this proposed standard. The effective date language covers the situation. No change made. The SDT agrees that it may be difficult to implement construction options in a one year time frame and that the limited use of Non-Consequential Load Loss may be an acceptable option. Footnote 'b' is not limited to Year One or to the Near-Term Transmission Planning Horizon since the footnote recognizes that Firm Demand can be interrupted throughout the entire planning horizon. As drafted, the standard defines the stakeholder process as mandatory for the Near-Term Transmission Planning Horizon since there may not be time to implement other corrective actions but does not limit its use in the Long-Term Transmission Planning Horizon. How individual entities reflect the Long-Term Transmission Planning Horizon situations in its individual stakeholder process is left to the entity to determine. No change made.		
Midwest Independent Transmission System Operator, Inc.	No	No. MISO objects to a stakeholder process as outlined in Attachment 1. See our comments under Question 5.
Response: Please see response to question 5.		
Electric Reliability Council of Texas, Inc.	No	Please see ERCOT's response to Question 1 - stakeholder processes are not appropriate for NERC standards.
Response: Please see response to question 1.		

Organization	Yes or No	Question 2 Comment
Public Service Company of New Mexico	No	PNM voted yes to the Standard as a whole but would like the SDT to consider the following concern: Part II.2.b of Attachment 1 that requires an assessment of the effect of the use of Non-Consequential Load Loss under Footnote B on the health, safety, and welfare of the community, and PNM believes that assessments of this nature are entirely subjective and will be difficult to comply with and even more difficult to audit. It is our belief that this criteria should be removed from the Standard prior to its ultimate submittal to NERC.
Response: The SDT understands the concerns and has clarified the wording accordingly. The intent of the SDT is that this action should be analogous to that required in approved EOP-001-2.1b. Section II, Bullet 2b. ~~Assessment~~ A description of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community		
NB Power Transmission	No	The process in Attachment 1 is overly prescriptive. Attachment 1, if retained, needs only to stipulate that the proposed utilization of the footnote be reviewed through an open and transparent stakeholder process in compliance with the applicable regulatory authority oversight.
Response: FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. No change made.		
Hydro One Networks Inc.	No	The process presented in Section I is overly prescriptive. If a section that prescribes the principles of a stakeholder process is required, then for non-US entities this section should simply require that the process must be approved by the applicable Regulatory Authority or Governmental Authority or its delegated agency that is responsible for local transmission and retail service for the load to be curtailed in that jurisdiction.
Response: Canadian entities are allowed to adopt ERO Reliability Standards, reject them outright, or adapt them for their own use		

Organization	Yes or No	Question 2 Comment
within the confines of provincial regulations. Nothing has changed in that regard with this proposed standard. The effective date language covers the situation. No change made.		
LCRA Transmission Service Corporation	No	
Response: Without specific comments, the SDT is unable to respond.		
Xcel Energy	Yes	The possibility of NCLL is always present, whether in the planning or operational arena. Section I (#5) should however specifically state that in the dispute resolution process a stakeholder does not have right of refusal for NCLL. This should be especially true when a transmission project has been proposed and NCLL in the interim is required due to the regulatory process, equipment lead time, etc. preventing the completion of project at an earlier time.
Response: Bullet #5 does not require specific attributes of the dispute resolution process. The SDT believes that the attributes of the stakeholder process should be defined by the entity during the development of the stakeholder process. No change made.		
MRO NSRF USACE MidAmerican Energy Company	Yes	(1) In Attachment 1 Section I, what is the definition of a "stakeholder"? Which NERC functional entities would be included (TO, TOP, LSE)? Are the public residential and/or business owners that are affected included in the definition? Some parties may assume that local government representatives or residential or business owners are included as stakeholders. We believe it is most appropriate for the Transmission Owners, Transmission Operators, and Load-Serving Entities to objectively evaluate the risks of load shedding in a local area against the cost impact of a large transmission project on the rate base. RECOMMENDATION: Define stakeholder to be "affected Transmission Owners, Transmission Operators, and Load-Serving Entities." (2) In Attachment 1 Section I item 1, what does "including applicable regulatory authorities" refer to? Is this the same body that "applicable regulatory authority or governing body" refers to in Section III? Are these requirements still applicable if the

Organization	Yes or No	Question 2 Comment
		25 MW threshold in Section III is not passed? RECOMMENDATION: Attachment 1 Section I Item 1 could read "... including applicable regulatory authorities or governing bodies responsible for retail electric service issues as described in Section III. A less vague statement allows the important parties to be included in every instance Attachment 1 is used.
Response: (1) In many instances, the affected stakeholders would be the same stakeholders identified in the Open Access Transmission Tariff planning process. However, the SDT believes that the planning entity has the best understanding of who an affected stakeholder will be and that any attempt to codify a list of such stakeholders in the proposed standards could lead to errors due to the necessity of having to adopt a one size fits all approach. No change made. (2) The term applies to any applicable, interested regulatory authority and is not necessarily the same body as mentioned in Section III. Conversely, the regulatory body cited in Section III would certainly be one of the regulatory bodies referred to in Section I. If the result of Section I is that the entity is not going to move forward with the plan, then Section III will never occur. No change made.		
Texas Reliability Entity	Yes	Attachment 1, section I (Stakeholder Process) should be clarified to specify which 'responsible entity' needs to utilize or develop a transparent stakeholder process. For example, if a contingency event in Entity A's system causes Entity B to have to shed non-consequential firm load to meet the BES performance requirements, which Entity is responsible for ensuring the required review? TRE proposes adding the following sentence to the first paragraph to assign responsibility for this type of scenario: "The Planning Coordinator or Transmission Planner accountable for the contingency event will be responsible for implementing the stakeholder process and regulatory review."
Response: The SDT believes that the current terminology is clear in that it is the entity that plans to utilize the footnote that needs to initiate the process. No change made.		
California Independent System Operator	Yes	There is no basis to support only allowing the utilization of the footnote in the Near-Term Transmission Planning Horizon of the Planning Assessment. The footnote itself should not explicitly restrict its utilization to only the Near-Term horizon. Often, in the long-term planning horizon, when approval for transmission addition or

Organization	Yes or No	Question 2 Comment
		reinforcement cannot be obtained for a variety of reasons, utilization of the footnote is considered and adopted, subject to stakeholder's and regulatory authority's approvals. Note that it is impractical to add or reinforce transmission facilities in a near-term planning (e.g. Year One) time frame and hence the proposed provision does not allow for utilizing the footnote for the interim period before new or reinforced transmission facilities are put in place. We suggest to remove the word "Near-Term".
Response: Footnote 'b' is not limited to the Near-Term Transmission Planning Horizon since the footnote recognizes that Firm Demand can be interrupted throughout the entire planning horizon. As drafted, the standard defines the stakeholder process as mandatory for the Near-Term Transmission Planning Horizon since there may not be time to implement other corrective actions but does not limit its use in the Long-Term Transmission Planning Horizon. How individual entities reflect the Long-Term Transmission Planning Horizon situations in its individual stakeholder process is left to the entity to determine. No change made.		
Southern California Edison Company	Yes	The Stakeholder Process in Section I of Attachment 1 is similar to the method effectively used by the CAISO to manage and incorporate stakeholder input in its annual transmission planning process.
Platte River Power Authority	Yes	Although these descriptive steps for a public process seem out of place in a reliability standard, Section 1 is in line with the planning principles of FERC Order 890.
Southwest Power Pool Reliability Standards Development Team	Yes	
Duke Energy	Yes	
Bonneville Power Administration	Yes	
Florida Municipal Power Agency	Yes	

Organization	Yes or No	Question 2 Comment
Arizona Public Service Company	Yes	
American Electric Power	Yes	
Deseret Generation & Transmission	Yes	
American Transmission Company	Yes	
Massachusetts Attorney General	Yes	
Idaho Power Company	Yes	
ISO New England	Yes	
Georgia Transmission Corp	Yes	
Modesto Irrigation District	Yes	
Response: Thank you for your support.		

3. **Do you agree with the Information for Inclusion in the Stakeholder Process contained in Section II of Attachment1? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: Most of the commenters asked questions about the intent of the SDT in particular areas and the SDT has provided individual responses accordingly.

There was one major overriding concern about Section II, Bullet 2b on the assessment on public health and safety. The SDT has clarified its intent and also pointed out that the action required for this bullet item is analogous to what is already required in approved EOP-001-2.1b.

Some commenters also questioned the use of the term 'mitigate' in Section II, Bullet 5. The SDT has clarified this language.

The following clarifying changes have been made due to industry comments:

TPL-002-1c: footnote b) - ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load.

Section II, Bullet 2b. ~~Assessment~~ An explanation of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community

Section II, Bullet #5. Future plans to ~~mitigate~~ alleviate the need for Firm Demand interruption under footnote 'b'

Organization	Yes or No	Question 3 Comment
TVA Transmission Reliability Engineering and Controls	No	TVA would like to propose that this Stakeholder process be postponed in the event that a transmission fix for a load drop issue was already planned within the next 2 or 3 years. Thus the stakeholder process would only occur for projects that had no fix planned within the next couple of years. TVA is also not sure how to satisfactorily address "health, safety, and welfare of the community" - TVA would appreciate some guidance on how to properly address this.

Organization	Yes or No	Question 3 Comment
		TVA believes that item 1.b of Section II could contain CEII information and should have limited distribution. The appropriate non-disclosure agreements would need to be developed to prevent widespread publication of the information.
Response: ~~:~~The SDT believes that the stakeholder process should occur whenever footnote ‘b’ is proposed to be utilized. The construction option in later years will be a part of the information provided in the stakeholder process for review. In this case, there will only need to be one review through the stakeholder process, if there are no material changes before the construction option is completed. No change made. The SDT understands the concerns and has clarified the wording accordingly. The intent of the SDT is that this action should be analogous to that required in approved EOP-001-2.1b. Section II, Bullet 2b. ~~Assessment~~ An explanation of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community If an entity believes that CEII information is involved then the entity should use the appropriate mechanisms to protect that information while still providing the basics of the information needed for the process to continue. No change made.		
ACES Power Marketing Standards Collaborators	No	(1) Adding the word “effect” on the health, safety, and welfare of the community creates more confusion regarding what is needed for the assessment. We recommend removing the effect clause from Section II. (2) We disagree that the Transmission Planner should be required to provide an assessment at all on the health, safety and welfare of the community. Attachment 1, Section 2a identifies the types of customers that are impacted without needing a formal assessment. Stakeholders will have an opportunity to provide information on impacts of planned load shedding through either the Transmission Planner’s stakeholder comment process or through the local regulatory agency’s stakeholder comment process. Further, these planned interruptions of firm demand are expected to be short in nature so any impact would be de minimis. Finally, an assessment on the health, safety and welfare of the community is an unnecessary burden on the registered entity and is better suited for local governments that can speak through the stakeholder process.

Organization	Yes or No	Question 3 Comment
		(3) Bullet 3 is based on available historical information. While this seems reasonable, we have concerns because of the rare instances that Non-Consequential Load Shed actually occurs. If a TP uses Non-Consequential Load Shed for the first time, there is no historical information. What would be an acceptable basis for the first use of Non-Consequential Load Shed when the entity is without historical information? (4) Expected time duration of the planned load shed is too speculative and should not be required because any duration will likely be a guess. When actual contingencies occur, the time of restoration varies and any time that was selected prior to the event is not likely to be correct. We do not see the value in predicting the duration time because there is too much uncertainty about how long an outage will really last. The SDT needs to clarify what is expected for the duration of the planned load shed. (5) While we appreciate that the response to our comments clarified the intent is that "Possible future plans could include a decision not to mitigate the need for Firm Demand interruption," the language in the Attachment simply does not reflect this. The Attachment specifically states "Future plans to mitigate the need for Non-Consequential Load Loss." A decision not to mitigate the need for Firm Demand interruption is not a future plan to mitigate. Consequently, Attachment 1, section II.5 will need to be modified to implement this intent. Otherwise, this language is certain to be interpreted as requiring a mitigation plan.

Response: (1) and (2) The SDT understands the concerns and has clarified the wording accordingly. The intent of the SDT is that this action should be analogous to that required in approved EOP-001-2.1b.

> Section II, Bullet 2b. ~~Assessment~~ An explanation of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community

(3) Historical performance is not limited to Contingencies which result in Non-Consequential Load Loss. The estimated frequency should be based on an entity's average historical performance of similar Facilities applied to the specific Element being evaluated. No change made.

Organization	Yes or No	Question 3 Comment
(4) The expected duration could be a range of values based on various assumptions. In the planning environment the entity should be able to analyze the situation and determine an expected duration for which an interruption would be in place. No change made. (5) The SDT agrees and has changed the language accordingly. 5. Future plans to ~~mitigate~~ alleviate the need for Firm Demand interruption under footnote 'b'		
Minnkota Power Cooperative Otter Tail Power Company	No	1. MPC QUESTION/COMMENT: In Attachment 1 Section II item 2b, "Assessment of the effect ... on the health, safety, and welfare of the community" is vague. Clarification is requested.a. RECOMMENDATION: Remove Item 2b because it requires the assessment of the footnote application impact on the potential health, safety, and welfare of the community. These types of assessments should be eliminated because they are not electric system reliability matters and were not stipulated by FERC. In the event that the Standards Development teams choses to keep item 2b, then add language semi-defining this as follows in Attachment 1 Section II Item 2b "...health, safety, and welfare of the community as determined by impact on critical health and emergency services." This allows the Transmission Planner and Planning Coordinator to identify the appropriate parties affected by the contingency to be analyzed in every instance Attachment 1 is used.
American Transmission Company	No	ATC recommends the following change in Section II of Attachment 1 applicable to both standards TPL-002-1c [page 8] and TLP-001-2a [page16]:Remove Item 2b altogether because it requires the assessment of the footnote application impact on the potential health, safety, and welfare of the community. These types of assessments should not be required in the Standards because they are not electric system reliability matters and were not stipulated within the FERC Order762.
Bonneville Power Administration	No	BPA does not support including information under Section II.2.b, an assessment of the use of Non-Consequential Load Loss on the health, safety, and welfare of the community. It would be nearly impossible for a planner to predict this in a future case since it is hard to predict what loads will actually materialize in the future. In addition, this information does not support reliability of the BES since reliability of

Organization	Yes or No	Question 3 Comment
		the transmission system is assessed by meeting required technical performance for certain contingencies and under certain conditions.
Arizona Public Service Company	No	Item 2b: Reference to health, safety, and welfare is unnecessary. All demand interruption are going to have some impact on health, safety, and welfare. The impact is subjective and will simply result in unnecessary study reports by consultants and will act as a road block.
Iberdrola USA	No	Regarding the documentation required for item 2.b, how are “health, safety, and welfare of the community” to be assessed? What are the metrics? How would compliance with this provision be evaluated?
MRO NSRF MidAmerican Energy Company USACE	No	Remove Item 2b because it requires the assessment of the footnote application impact on the potential health, safety, and welfare of the community. These types of assessments should be eliminated because they are not electric system reliability matters and were not stipulated by FERC.
Southern California Edison Company	No	SCE participates in the rigorous CAISO annual transmission planning process that considers the information included in the proposed Section II of Attachment 1. However, the proposed language in Section II.2.b. “Assessment of the effect of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community,” seems overly broad and confusing. The California Public Utility Commission (CPUC) and CAISO presently consider these items before approving transmission plans. It is unclear what type of information would be required in order to meet the seemingly broad request contained in Section II.2.b. SCE believes that the language of Section II.2.b. should be removed from Attachment 1, or alternatively, the language should be revised to specifically exempt critical loads, such as hospitals, fire department facilities, law enforcement facilities, and correctional facilities.
Public Utility District No.1 of	No	We suggest removing section 2b “Assessment...health, safety...” for three reasons:

Organization	Yes or No	Question 3 Comment
Snohomish County MEAG Power Clark Public Utilities		1)All outages have a negative impact on the community. Outages under footnote 12 do not inherently have more significant impact per MWhr lost than other outages allowed per Table 1. By requiring additional analysis for a similar societal impact, this provision discriminates against utilities at the fringes of the system. 2) While reminding planners to consider that their decisions do have real impacts to real people is a laudable goal, including this provision opens the door to significant legal liability and regulatory uncertainty. 3) An appendix to a footnote is the wrong place to introduce such a significant requirement. The Adequate Level of Reliability Task Force would be a more appropriate venue for this idea.
Tacoma Power City of Austin	No	We suggest removing section 2b “Assessment...health, safety...” for three reasons: 1)All outages have a negative impact on the community. Outages under footnote 12 do not inherently have more significant impact per MWhr lost than other outages allowed per Table 1. By requiring additional analysis for a similar societal impact, this provision discriminates against utilities at the fringes of the system. 2) While reminding planners to consider that their decisions do have real impacts to real people is a laudable goal, including this provision opens the door to significant legal liability and regulatory uncertainty. 3) An appendix to a footnote is the wrong place to introduce such a significant requirement. The Adequate Level of Reliability Task Force would be a more appropriate venue for this idea.
Response: The SDT understands the concerns and has clarified the wording accordingly. The intent of the SDT is that this action should be analogous to that required in approved EOP-001-2.1b. Section II, Bullet 2b. ~~Assessment~~ An explanation of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community		
Tri-State Generation & Transmission Association	No	In the NERC Glossary of Terms, Interruptible Demand is defined as “Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.” The process described in Attachment 1 creates an agreement between stakeholders (aka “end-use customers”) and their transmission providers. Thus, if the process described in Attachment 1 is followed, the “Firm

Organization	Yes or No	Question 3 Comment
		Demand" referenced would be reclassified as "Interruptible Demand." In essence, "Footnote b" does not allow the interruption of Firm Demand. It merely requires that if interruption of Demand is required, it can only be Interruptible Demand. If this was the intention of FERC, NERC, and the Drafting Team, why didn't the drafting team just state "Interruption of Firm Demand is not allowed"?
Response: Upon reviewing the comments, the SDT has seen that a clarification for Demand that is not included as Firm Demand for footnote 'b' could be clarified as shown below. TPL-002-1c: footnote b) - ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load.		
Independent Electricity System Operator	No	No. The process presented in Section II is overly prescriptive. If a section that prescribes the information requirements for a stakeholder process is required, then for Canadian entities this section should simply state that any threshold should be established in a manner consistent with other service levels that apply to local transmission and retail service for the load to be curtailed.
Hydro One Networks Inc.	No	The process presented in Section II is overly prescriptive. If a section that prescribes the information requirements for a stakeholder process is required, then for non-US entities this section should simply require that the process information requirements must be in accordance with the requirements of the applicable Regulatory Authority or Governmental Authority or its delegated agency that is responsible for local transmission and retail service in that jurisdiction.
Response: Canadian entities are allowed to adopt ERO Reliability Standards, reject them outright, or adapt them for their own use within the confines of provincial regulations. Nothing has changed in that regard with this proposed standard. The effective date language covers the situation. No change made.		
Midwest Independent Transmission System Operator,	No	No. MISO objects to a stakeholder process as outlined in Attachment 1. See our

Organization	Yes or No	Question 3 Comment
Inc.		comments under Question 5.
Response: Please see response to question 5.		
Electric Reliability Council of Texas, Inc.	No	Please see ERCOT's response to question 1-the NERC Reliability Standards should not contain requirements related to stakeholder processes, whether they are procedural or substantive. If an exception process is retained, it should be outside of the NERC Reliability Standards (e.g. in the Rules of Procedure). To the extent the proposed standard inappropriately retains the stakeholder related aspects, ERCOT also provides the following comments on Section II-the ERCOT comments are in parentheses for easy reference and distinction relative to the proposed requirements.II. Information for Inclusion in Item #3 of the Stakeholder ProcessThe responsible entity shall document the planned use of Firm Demand interruption under footnote 'b' which must include the following: (ERCOT COMMENT: This is all that is needed for this. The documentation would be relative to the objective criteria developed for this purpose.) 1. Conditions under which Firm Demand interruption under footnote 'b' would be necessary:a. System Load level and estimated annual hours of exposure at or above that Load levelb. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency(ERCOT COMMENT: "1" is not necessary if objective criteria are developed as benchmarks for the exception process. In that case, exceptions would only be allowed if the objective criteria were met, regardless of the underlying assumptions related to conditions and contingencies.) 2. Amount of Firm Demand MW to be interrupted with:a. The estimated number and type of customers affectedb. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community(ERCOT COMMENT: The considerations reflected in a and b are inappropriate for a reliability standard. Appropriate considerations for reliability standards are related to the reliability performance of the system. The considerations in a and b are more akin to quality of service issues better suited for

Organization	Yes or No	Question 3 Comment
		regional policy discussions. It is not within the purview of the SDT to address those matters.) 3. Estimated frequency of Firm Demand interruption under footnote 'b' based on historicalPerformance (ERCOT COMMENT: Historical performance is irrelevant. If the SDT is going to retain revisions that accommodate non-consequential load shedding, then the only relevant metrics are the objective criteria that set the benchmarks for such exceptions.) 4. Expected duration of Firm Demand interruption under footnote 'b' based on historical performance(ERCOT COMMENT: See ERCOT response to "3" above.) 5. Future plans to mitigate the need for Firm Demand interruption under footnote 'b'(ERCOT COMMENT: This is redundant to the requirement in the reliability standards that requires a plan to resolve any violations identified in the planning process.Furthermore, if load shedding is allowed, this requirement doesn't make sense. Presumably the idea behind allowing these exceptions is to obviate the prospective need for other alternatives. If that is not the case, then there is no need to allow the exceptions, because the transmission upgrades to mitigate the need for load shedding can be established in the planning horizon.) 6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 'b'(ERCOT COMMENT: The basis for the load shedding exception is to provide a means to meet the TPL performance requirements in the context of a planning assessment. Accordingly, this is redundant to the planning assessments, the point of which is to identify and resolve performance issues.) 7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote 'b'(ERCOT COMMENT: Load shedding exceptions should be based on objective criteria and be reviewed pursuant to a process external to the NERC reliability standards. Alternative discussions could be part of that external process.)

Organization	Yes or No	Question 3 Comment
		8. Assessment of potential overlapping uses of footnote 'b' including overlaps with adjacent Transmission Planners and Planning Coordinators(ERCOT COMMENT: It is not clear what this means. Each functional entity performs assessments relative to its own system. This appears to introduce a vague regional transmission planning requirement with no structure or rules for such assessments.)
Response: Please see response to question 1. The SDT believes that the criteria in Section II are objective and represent the information that a stakeholder will want to see for assistance in determining their position on proposed planned actions. The SDT reminds the commenter that this process will involve some parties that are not experts in interpreting assessments and that these parties will need information that may be considered redundant or superfluous in other settings. Items such as historical performance would fall into this realm. No change made. The SDT has revised the language of bullet #5 due to other comments received. 5. Future plans to ~~mitigate~~ alleviate the need for Firm Demand interruption under footnote 'b' Bullet #8 does not introduce a regional planning requirement. It is consistent with Requirement R8 in proposed TPL-001-2a that mandate sharing of Planning Assessments. No change made.		
Xcel Energy	No	Section II should be left as part of the resolution in the dispute process and should not be made a requirement. Some in particular include:Â§ II.1. - this should be based only on applicable contingencies or conditions that could require NCLL. Having to include the estimated hours at or above a load level may not always be the most effective way to convey why NCLL will be used and adds little to the argument of why or why not it needs to be used. Â§ II.2.a - This may not always be apparent to the TO serving a wholesale transmission customers (REC, MUNICIPAL, etc.). This should be eliminated since it does little in emphasizing the need for NCLL. Â§ II.2.b - The "effect" of the use of NCLL may not always be apparent, because it is a perceived condition of what could happen that can be interpreted differently. I agree that it should be mentioned in the Stakeholder process outlining the locations

Organization	Yes or No	Question 3 Comment
		where NCLL will take place and let the dispute process identify and assess the health, safety and welfare of the community. How do you assess the effect in the Planning of NCLL. The effect should be identified by the party being affected and resolved in the dispute process. Â§ II.3 & 4. - This needs to be eliminated. Expected frequency and duration of NCLL based on historical performance DOES NOT GUARANTEE future performance and does little in emphasizing the need for NCLL. II.8 - This should be addressed by the Regional Planning Authority in their regional studies.
Response: The SDT disagrees and believes that the criteria in Section II represent the information that a stakeholder will want to see for assistance in determining their position on proposed planned actions. The SDT reminds the commenter that this process will involve some parties that are not experts in interpreting assessments and that these parties will need information that may be considered redundant or superfluous in other settings. Items such as historical performance would fall into this realm. No change made.		
ISO New England	No	Section II, 2.a states that studies must address the estimated number and type of customers affected by Non-Consequential Load Shedding. This language should be removed for three reasons.(1) This appears to be inappropriate for a reliability standard. The specific number and type of customers within a set number of MWs that are electrically acceptable do not impact the reliability of the bulk electric system (as defined by Section 215 of the Federal Power Act). (2) Even if the number and type of affected customers were an appropriate process question for an ERO standard, the number and type of customers may change depending on particular system configuration at the time of the load shedding. For example, a substation may be reconfigured to address other system issues such as maintenance and a certain number of MWs of load being interrupted, while still electrically acceptable from a system reliability perspective, may impact different numbers and types of customers. (3) Assuming that the number and type of customers affected were an appropriate metric, the Transmission Planner in many cases will not be the

Organization	Yes or No	Question 3 Comment
		appropriate entity to address these concerns. The Transmission Owner, Distribution Provider or Load Serving Entities would be the appropriate entities to address customer affects. Section II, 2.b should be revised to delete the reference to "health, safety, and welfare of the community." It is inappropriate for a NERC Standard to require planners to address the "health, safety, and welfare of the community." NERC's authority appears limited to regulating the "reliability" of the bulk electric system. Section 215 specifies that NERC's authority it to establish Reliability Standards necessary to ensure an "adequate level of reliability." Reliability Standards may specify the "design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation." Section 215 defines "reliable operation" as "operating the elements of the BPS within equipment and electrical system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements." Establishing this requirement is also arbitrary, because it is inconsistent with other transmission planning requirements. For example, the same load could be shed directly as the consequence of a fault and no such assessment is required. In addition, Transmission Planners can plan for the shedding of radial load with no assessment of health, safety and welfare. Section II, requirements 3 and 4 discuss estimating frequency and duration of Non-Consequential Load Loss based on historical performance. This provision is inconsistent with the manner in which transmission system planning is conducted and should be removed. The transmission system planning process uses deterministic not probabilistic assessments. While a power system may utilize these factors in assessing where the use of non-consequential load loss may be acceptable in terms of providing service, these factors do not inform reliability risks to the bulk electric system where the loss of load is found to be electrically acceptable in terms of system reliability (i.e., no thermal, voltage, or stability issues are created or

Organization	Yes or No	Question 3 Comment
		exacerbated and no instability, uncontrolled separation, or cascading failures result).
Response: The SDT believes that the criteria in Section II represent the information that a stakeholder will want to see for assistance in determining their position on proposed planned actions. The SDT reminds the commenter that this process will involve some parties that are not experts in interpreting assessments and that these parties will need information that may be considered redundant or superfluous in other settings. Items such as historical performance would fall into this realm. No change made. The SDT understands the concerns and has clarified the wording. The intent of the SDT is that this action should be analogous to that required in approved EOP-001-2.1b. Section II, Bullet 2b. ~~Assessment~~ An explanation of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community The SDT believes that the criteria in Section II represent the information that a stakeholder will want to see for assistance in determining their position on proposed planned actions. The SDT reminds the commenter that this process will involve some parties that are not experts in interpreting assessments and that these parties will need information that may be considered redundant or superfluous in other settings. Items such as historical performance would fall into this realm. No change made.		
SCE&G	No	We believe that item 1.b of Section II may contain Critical Energy Infrastructure Information (CEII) and should have limited distribution. The appropriate non-disclosure agreements would be required in order to prevent widespread publication of the information.
SERC EC Planning Standards Subcommittee Associated Electric Cooperative	No	We believe that item 1.b of Section II would contain CEII information and should have limited distribution. The appropriate non-disclosure agreements would need to be developed to prevent widespread publication of the information.
Response: If an entity believes that CEII information is involved then the entity should use the appropriate mechanisms to protect that information while still providing the basics of the information needed for the process to continue. No change made.		
NBSO	No	We do not agree with the need for Section II (and Attachment I as a whole) at all. The footnote, or Attachment I, should only stipulate that when Non-Consequential Load Loss is needed to ensure that BES performance requirements are met, then

Organization	Yes or No	Question 3 Comment
		regulatory approval from local jurisdiction needs to be provided with demonstration that the approval was obtained through an open stakeholder process.
Response: The SDT believes that the criteria in Section II represent the information that a stakeholder will want to see for assistance in determining their position on proposed planned actions. The SDT reminds the commenter that this process will involve some parties that are not experts in interpreting assessments and that these parties will need information that may be considered redundant or superfluous in other settings. Items such as historical performance would fall into this realm. No change made.		
LCRA Transmission Service Corporation	No	
NB Power Transmission	No	
Response: Without specific comments, the SDT is unable to respond.		
Texas Reliability Entity	Yes	In Section II, part 1b, TRE suggests replacing 'applicable rating' with 'steady state performance requirments', to account for all the BES performance requirements (in particular, steady-state and post-contingency voltages) for which the footnote may be utilized.
Response: Applicable ratings are the basis for the performance requirements in Table 1 of proposed TPL-001-2a. Therefore, the SDT believes that the existing terminology correctly addresses the performance issue. No change made.		
Southwest Power Pool Reliability Standards Development Team	Yes	In this section the reference to Customers should only be Customers of Transmission and not open ended for any customer. Once it is sold wholesale the TP wouldn't know where it is being sent to. We would also note that under some jurisdictions that there is a minimum duration threshold for keeping historical data on some of these events that are being requested under this section. Need to add language to accommodate these thresholds so as not to contradict what is being asked for by the regulatory bodies.
Response: The SDT disagrees that the only customers that should be considered are wholesale customers. The total number of		

Organization	Yes or No	Question 3 Comment
customers affected is information that helps other stakeholders understand the full impact of the planned usage of footnote 'b'. The SDT also disagrees that the Transmission Planner will not know where the Load will be lost. The Transmission Planner cannot evaluate the impacts of interrupting Firm Demand without knowing where the Load is connected to the BES system. The historical information is not related to historical planned Load interruption, but rather the historical performance of similar Facilities. However, If an entity does not have its own historical information available then it should use other available data to make its best estimate of what the values will be. No change made.		
New England States Committee on Electricity (NESCOE)	Yes	NESCOE agrees with the list provided in Section II. Regarding item #7, in the interest of explicit direction, NESCOE suggests adding at the end of the sentence the following language: "and cost comparisons of all alternatives."
Response: Cost considerations will be part of a rationale for selection or non-selection of an alternative. The SDT believes the current terminology captures this concept. No change made.		
Ameren	Yes	We believe that item 1b of Section II would contain critical electric infrastructure information (CEII) and should have limited distribution. The appropriate non-disclosure agreements would need to be developed to prevent widespread publication of the material.
Response: If an entity believes that CEII information is involved then the entity should use the appropriate mechanisms to protect that information while still providing the basics of the information needed for the process to continue. No change made.		
Duke Energy	Yes	
Florida Municipal Power Agency Lakeland Electric Gainesville Regional Utilities	Yes	
Southern Company	Yes	

Organization	Yes or No	Question 3 Comment
Western Area Power Administration	Yes	
American Electric Power	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Deseret Generation & Transmission	Yes	
Platte River Power Authority	Yes	
Massachusetts Attorney General	Yes	
California Independent System Operator	Yes	
Public Service Company of New Mexico	Yes	
Idaho Power Company	Yes	
Georgia Transmission Corp	Yes	
Modesto Irrigation District	Yes	
Response: Thank you for your support.		

4. Do you agree with the text in Section III of Attachment 1? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Summary Consideration: The majority of the comments received here are similar to those submitted for question 1 and similar responses have been provided.

The following clarifying changes were made due to industry comments:

TPL-002-1c: footnote b) - ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load.

Attachment 1, Section III, first paragraph: Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ~~assure~~ ensure that the applicable regulatory ~~authority~~ authorities or governing ~~body~~bodies responsible for retail electric service issues do~~es~~ not object to the use of Firm Demand interruption under footnote 'b' if either:

Attachment 1, Section III, last paragraph: Once assurance has been received that the applicable regulatory ~~authority~~ authorities or governing ~~body~~bodies responsible for retail electric service issues do~~es~~ not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.

Organization	Yes or No	Question 4 Comment
Public Utility District No.1 of Snohomish County MEAG Power City of Austin Clark Public Utilities	No	1) Similar to our comment on question 2, please remove the words "as an element of a Corrective Action Plan" from the first sentence. There are cases on the fringes of the system where Non-Consequential Load Loss is the preferred alternative in both the long term and short term, not as a temporary patch. Since a Corrective Action Plan is a "list of actions and an associated timetable for implementation to remedy a specific problem," using this term removes the stakeholders ability to evaluate the costs and benefits and instead requires them to treat this a problem where the only solution is building new facilities.

Organization	Yes or No	Question 4 Comment
		2) For any specific use of footnote b, there could be several applicable regulatory authorities such as small municipalities or public utility districts. The standard should clarify whether the planner must show evidence that every authority did not object, or whether the planner only needs to show that less that 25 MW was not rejected by the regulatory authorities. To accomplish this clarification, we propose: A) In Section III paragraph 1 and paragraph 5 change "regulatory authority or governing body" to "regulatory authorities or governing bodies." B) Add a sentence to bullet 2 to read "If multiple regulatory authorities or governing bodies are responsible for retail electric service issues, only the portion of Non-Consequential Load Loss exceeding 25 MW is subject to section III."
Tacoma Power	No	1) Similar to our comment on question 2, please remove the words "as an element of a Corrective Action Plan" from the first sentence. There are cases on the fringes of the system where Non-Consequential Load Loss is the preferred alternative in both the long term and short term, not as a temporary patch. Since a Corrective Action Plan is a "list of actions and an associated timetable for implementation to remedy a specific problem," using this term removes the stakeholders ability to evaluate the costs and benefits and instead requires them to treat this a problem where the only solution is building new facilities. 2) For any specific use of footnote b, there could be several applicable regulatory authorities such as small municipalities or public utility districts. The standard should clarify whether the planner must show evidence that every authority did not object, or whether the planner only needs to show that less that 25 MW was not rejected by the regulatory authorities. To accomplish this clarification, we propose: A) In Section III paragraph 1 and paragraph 5 change "regulatory authority or governing body" to "regulatory authorities or governing bodies." B) Add a sentence to bullet 2 to read "If multiple regulatory authorities or governing bodies are responsible for retail electric service issues, only the portion of Non-Consequential Load Loss exceeding 25 MW is subject to section III."

Organization	Yes or No	Question 4 Comment
Response: (1) The SDT disagrees. When alternatives and the rationale for selection or non-selection of those alternatives are presented, cost factors can certainly be part of the rationale. In proposed TPL-001-2a, Requirement R2, Part 2.7.1, a list of possible actions that could be included in a Corrective Action Plan is provided. This list shows several alternatives that do not require the building of new Facilities. No change made. (2) The SDT agrees that the plural use of the terms shown in A) above should be consistent throughout the document and has made corresponding changes to reflect this. The SDT does not agree with the proposed change shown in B). The footnote is applicable for a single Contingency and ownership or jurisdictional concerns do not come into play. The total value of Load affected by the single Contingency is the correct value to determine if the situation is subject to Section III. Attachment 1, Section III, first paragraph: Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ~~assure~~ ensure that the applicable regulatory ~~authority~~ authorities or governing ~~body~~bodies responsible for retail electric service issues do~~es~~ not object to the use of Firm Demand interruption under footnote 'b' if either: Attachment 1, Section III, last paragraph: Once assurance has been received that the applicable regulatory ~~authority~~ authorities or governing ~~body~~bodies responsible for retail electric service issues do~~es~~ not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.		
MRO NSRF USACE	No	(1) In Attachment 1 Section III, what is the definition of "applicable regulatory authority or governing body"? Is this the state PSC or PUC? Is it the Regional Reliability Organization (RRO)? Is it the Reliability Coordinator (RC)? RECOMMENDATION: Depending on the answer to the above question, define "applicable regulatory authority or governing body" more precisely. The language could read "applicable regulatory authority or governing body responsible for retail electric service such as the state Public Services Commission or Public Utilities Commission". A less vague statement allows the important parties to be included in every instance Attachment 1 is used. (2) In Attachment 1, if non-consequential load loss is planned at multiple bulk delivery points to mitigate the same contingency should the total load loss count

Organization	Yes or No	Question 4 Comment
		towards the 25 MW and 75 MW thresholds or should the loads be counted individually? EXAMPLE: There are two load serving substations (X load at substation B and Y load at substation C) on a long 115 kV line with 230/115 kV transformation at each end (substation A and substation D). Automatic under-voltage load shedding is in place at substations B and C, the UVLS relays at each substation making load trip decisions based on local voltage (i.e. independent operation). If one end of the 115 kV line trips and 115 kV voltage is below allowable levels at both substations X and Y, then the total load tripped by UVLS will be X+Y. Does the X+Y value count towards the 25 MW and 75 MW thresholds or are X and Y counted separately? What if X load is dropped for one contingency and Y load is dropped for a different contingency, is the total load counted X+Y or each load separately? RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote 'b' could read "In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for any single contingency." Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion. (3) If non-consequential load loss is planned at multiple bulk delivery points in close proximity to mitigate different contingencies should the total load loss count towards the 25 MW and 75 MW thresholds or should the loads be compared individually? For example, there are two load serving substations (X load at substation B and Y load at substation C) on a networked 115 kV line with 230/115 kV transformation at both ends (substation A and substation D). Automatic under-voltage load shedding is in place at substations B and C that would trip X amount of load if one end of the 115 kV line tripped and 115 kV voltage was below allowable levels, and would trip Y amount of load if the other end of the 115 kV line tripped and 115 kV voltage was below allowable levels. Does the X+Y value count towards the 25 MW and 75 MW thresholds or are X and Y counted separately? In addition to the aforementioned contingencies, if the 115 kV line between substations B and C opens, both loads X and Y will trip. Now does the X+Y value count towards the 25

Organization	Yes or No	Question 4 Comment
		MW and 75 MW thresholds? (4) In Attachment 1, if UVLS relaying is programmed at a sub to trip the load in stages at multiple voltage setpoints, such that only a fraction of the load is tripped for a given contingency, is the entirety of the load still counted towards the 25 MW and 75 MW thresholds? EXAMPLE: Substation B has X load that will trip if the BES voltage gets to 0.92 p.u. and Y that will trip if the BES voltage gets to 0.88 p.u. If only X amount of load is required to mitigate a single contingency in the near-term TPL assessment, is X load counted towards the 25 MW and 75 MW thresholds or is X+Y load counted? Is there a difference if the Y load is at a different, nearby substation with both loads having the aforementioned tripping logic? RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote 'b' could read "In no case can the planned Firm Demand interruption under footnote 'b' (as demonstrated in the near-term horizon analysis) exceed 75 MW." Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion
Minnkota Power Cooperative Otter Tail Power Company	No	1. MPC QUESTION: In Attachment 1 Section III, what is the definition of "applicable regulatory authority or governing body"? a. Is this the state Public Service Commission or Public Utilities Commission, the Regional Reliability Organization (RRO), and/or the Reliability Coordinator (RC)? b. RECOMMENDATION: Depending on the answer to the above question, define "applicable regulatory authority or governing body" more precisely. The language could read "applicable regulatory authority or governing body responsible for retail electric service such as the state Public Services Commission or Public Utilities Commission". A clearly defined statement allows the Transmission Planner and Planning Coordinator to identify the appropriate parties to be included in every instance Attachment 1 is used. 2. MPC QUESTION: In Attachment 1, if non-consequential load loss is planned at multiple bulk delivery points to mitigate the same contingency should the total load loss count towards the 25 MW and 75 MW thresholds or should the loads be

Organization	Yes or No	Question 4 Comment
		counted individually? a. EXAMPLE: There are two load serving substations (X load at substation B and Y load at substation C) on a long 115 kV line with 230/115 kV transformation at each end (substation A and substation D). Automatic under-voltage load shedding is in place at substations B and C, the UVLS relays at each substation making load trip decisions based on local voltage (i.e. independent operation). If one end of the 115 kV line trips and 115 kV voltage is below allowable levels at both substations X and Y, then the total load tripped by UVLS will be X+Y. i. Does the X+Y value count towards the 25 MW and 75 MW thresholds or are X and Y counted separately? ii. What if X load is dropped for one contingency and Y load is dropped for a different contingency, is the total load counted X+Y or each load separately? b. RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote ‘b’ could read “In no case can the planned Firm Demand interruption under footnote ‘b’ exceed 75 MW for any single contingency.” Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This clarification would explain much more clearly what is counted towards the two thresholds and decrease confusion. 3. MPC QUESTION: In Attachment 1, if UVLS relaying is programmed at a sub to trip the load in stages at multiple voltage setpoints, such that only a fraction of the load is tripped for a given contingency, is the entirety of the load still counted towards the 25 MW and 75 MW thresholds? a. EXAMPLE: Substation B has X load that will trip if the BES voltage gets to 0.92 p.u. and Y that will trip if the BES voltage gets to 0.88 p.u. i. If only X amount of load is required to mitigate a single contingency in the near-term TPL assessment, is X load counted towards the 25 MW and 75 MW thresholds or is X+Y load counted? ii. Is there a difference if the Y load is at a different, nearby substation with both loads having the aforementioned tripping logic? b. RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote ‘b’ could read “In no case can the planned Firm Demand interruption under footnote ‘b’ (as demonstrated in the near-term horizon analysis) exceed 75 MW at a single substation.” Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain

Organization	Yes or No	Question 4 Comment
		much more clearly what is counted towards the two thresholds and decrease confusion.
Response: (1) The SDT believes that any attempt to more specifically enumerate regulatory bodies will result in the exact opposite effect of what is stated in that inevitably there will be a one-off situation that doesn't fit the statement. The SDT believes that the entity will know who needs to be involved and will take the appropriate steps to make certain that the correct parties are involved. No change made. (2) Footnote 'b' only applies to single Contingencies so the SDT believes that adding the suggested words would be redundant. In the specific example cited, if the actions taken are the result of the same single Contingency, then the total value of the Load shed would be applicable. No change made. (3) If the Load shed is the result of different Contingencies, the proximity doesn't matter and the Load would be counted separately. (4) The SDT believes that the suggested wording would be redundant. Only Load shed due to a single Contingency is applicable here. No change made.		
ACES Power Marketing Standards Collaborators	No	(1) We disagree with the threshold of 75 MW, as mentioned above.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made.		
Southern California Edison Company	No	As applied to SCE's service territory, Section III of Attachment 1 appears to require written acknowledgement and approval by the CPUC of each and every Firm Demand interruption authorized by the CAISO's annual transmission plan. In California, the CPUC is notified of and invited to every CAISO meeting on transmission planning, but the CPUC generally does not provide specific written assurances or agreement on detailed elements of the CAISO transmission plan. SCE believes that a general approval of the overall plan from the regulatory body should

Organization	Yes or No	Question 4 Comment
		be adequate.
Response: The SDT disagrees that formal approval is required for every instance of Firm Demand interruption as Section III only applies for Load over 25 MW. Obtaining assurance from regulators that they do not object will undoubtedly occur in different ways. Some regulators may provide written assurances or agreement but that is not required by the standard. No change made.		
Bonneville Power Administration	No	For use of Non-Consequential Load Loss in Year One of the Planning Assessment, BPA believes that assurance received from the applicable regulatory authority or governing body responsible for retail electric service issues is adequate and submission to the ERO for a determination of adverse impact is unnecessary. The local utility and regulators are better positioned to determine adverse impacts on an individual system, whereas the ERO would have to develop a process and criteria for assessing adverse impacts.
Response: The remand Order made it clear that oversight was required for instances where use of footnote 'b' was proposed. The ERO is aware of the proposed responsibility and has accepted this role if the industry approves. No change made.		
Tri-State Generation & Transmission Association	No	How would section III of "Attachment 1" be applied to entities that only deliver wholesale electric service and no retail electric service?
Response: The SDT believes that the wholesale customer will be one of the stakeholders included in the process and any use of the footnote must go through the stakeholder process. No change made.		
Modesto Irrigation District	No	I am voting NO because there is no technical basis for use of the 75 and 25 MW absolute threshold values, regardless of the size of the utility's load, referenced in the proposed standard. WECC's past experience with implementation of arbitrary magnitudes for requirements (e.g., the 5% and 7% arbitrary magnitude contingency reserve requirements), has proved to be problematic. I would suggest investigating a technical basis for using a relative requirement, such as percentage of the utility's load, maybe 5% and 2.5%, respectively, and that it be based on technical requirements similar to those found in Table 1 of the WECC Criteria TPL-001-WECC-

Organization	Yes or No	Question 4 Comment
		CRT-2.Thank you.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. Utilizing a percentage of an entity's Load may be problematic – when dealing with a small entity it could be a small value but still of rather large import and if dealing with a large entity could result in significant amounts of Load shed being planned. And, the FERC Order states that a percentage approach would not be appropriate for the aforementioned reasons. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made.		
Electric Reliability Council of Texas, Inc.	No	If non-consequential load shedding is allowed for single contingency conditions, as discussed above, it should be based on objective critieria. As such, there is no need for the proposed stakeholder process, including the Section Ill instances requiring regulatory review. Furthermore, establishing approval roles in planning processes for entities other than the relevant functional entities conflicts with the appropriate roles, and appropriate separation of those roles, of the relevant entities (i.e. the planning authority and the state regulatory body and NERC RE). Typically a functional entity performs the functional activity, and others relevant to the proposed process in the standard perform compliance and regulatory oversight of the functional performance. This is a practical concern, and also potentially raises conflicts between governing authorities that create the separation of roles, where, typically, the relevant authorities establish a functional entity as the planning entity, and NERC and its REs and state regulators (as relevant - e.g. in ERCOT) are charged with compliance and regulatory oversight. As with the other stakeholder process sections, that section should be eliminated.
Response: The SDT used the Board of Trustees approved standard as a starting point for this draft. FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted		

Organization	Yes or No	Question 4 Comment
draft added detail and specificity to the already approved approach. No change made. The SDT believes that the role provided to regulatory bodies is consistent with current practices in the industry today. While formal approval may not be provided by some regulatory bodies as pointed out in other comments, Section III does not require formal approval but rather a lack of dissent. No change made.		
National Association of Regulatory Utility Commissioners	No	It appears that the 25 MW minimum value is merely a reflection of antidotal information from a small number of data request responders and as such is not technically justified. NARUC is not poised to offer an alternative; given that the State/local regulator is consulted in this process, States should be appraised if any load is anticipated to be shed under any planning criteria. Thus, no mimimum value should be set.
Response: The data request is not anecdotal information. All of the Transmission Planners in the continental United States supplied their data in response to the data request. The SDT believes it is unrealistic to consider the allowable usage of footnote 'b' in the planning process without a cap on the amount of Load planned to be shed. The SDT also believes that such a position is consistent with the wording in the Order. Absent any alternative suggestion and given the participation of appropriate regulatory bodies in both Sections I and III, the SDT believes that the current threshold is the best possible solution. No change made.		
Xcel Energy	No	It does not appear that an entity has any options if the applicable regulatory authority or governing body objects to the use of NCLL in year one. This could potentially occur as a result of load patterns and generation issues submitted by an LSE not necessarily having BES elements and the only solution is to implement NCLL. In year one, it is too late to build any necessary and NCLL may be the only alternative.
Response: While the requirement is not mandatory until Year One, the SDT believes that it would be a good practice to move forward as soon as an entity knows it is contemplating usage of the footnote. That way, alternatives can be openly discussed before time becomes an overriding concern. The instance described above points to the need for the stakeholder process as this process will facilitate closer coordination with the Load-Serving Entities providing the information and the applicable regulators. No change made.		

Organization	Yes or No	Question 4 Comment
MidAmerican Energy Company	No	Item III of Attachment I should be deleted completely. Non ERO regulatory review is not necessary. Applicable regulatory authority or governing bodies responsible for retail electric service issues are stakeholders which may participate in the stakeholder process. Further, there are concerns compliance may not be possible because item III makes non-NERC applicable regulatory authorities or governing bodies responsible for retail electric service issues part of a NERC mandatory compliance without consequence to the said non-NERC governing bodies. Non-NERC entities are not constrained by NERC mandatory laws and penalties and aren't compelled to perform actions to meet NERC compliance. This opens a risk to any NERC regulated entities governed by such regulatory or governing bodies that do not or may not feel compelled to have a process for the NERC regulatory review specified in item III of attachment I.
Response: The SDT believes that the role provided to regulatory bodies is consistent with current practices in the industry today. While formal approval may not be provided by some regulatory bodies as pointed out in other comments, Section III does not require formal approval but rather a lack of dissent. No change made.		
New England States Committee on Electricity (NESCOE)	No	NESCOE is concerned that the 25 MW minimum value for regulatory review lacks sufficient technical justification. NESCOE understands that the SDT used responses to data requests to establish this 25 MW value, which is based on the average number of MWs that entities applying footnote “b” reported using in transmission planning. This may be a good starting point, but additional analysis is warranted. Specifically, the analysis should consider a more direct nexus to the system, such as substation design criteria. Additionally, as detailed above, Attachment 1 should provide clarity regarding the meaning of “applicable regulatory authorities.” Moreover, clarification is required regarding the initial triggering factor for regulatory review. Section III states that the regulatory review process is required before the footnote can be utilized in “Year One” of the planning horizon. Does this mean that such regulatory review only applies to year one or does it apply to year one and beyond?

Organization	Yes or No	Question 4 Comment
		If the former, NERC needs to provide a clear rationale for restricting such review when limiting factors are already applied (i.e., voltages greater than 300 kV or a 25 MW minimum threshold value).

Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote ‘b’ by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote ‘b’. Other considerations can be a point of reference or sanity check but in and of themselves are not sufficient for setting a threshold in this matter. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach and that no further research is required. No change made.

The SDT believes that any attempt to more specifically enumerate regulatory bodies will result in the exact opposite effect of what is stated in that inevitably there will be a one-off situation that doesn’t fit the statement. The SDT believes that the entity will know who needs to be involved and will take the appropriate steps to make certain that the correct parties are involved. The only mandated trigger for review is the need to have met the stipulations of the footnote and attachment prior to utilizing Load shed for single Contingencies in a Corrective Action Plan in Year One. While the requirement is not mandatory until Year One, the SDT believes that it would be a good practice to move forward as soon as an entity knows it is contemplating usage of the footnote. That way, alternatives can be openly discussed before time becomes an overriding concern. No change made.

As stated, the review is only required prior to utilizing the footnote in a Corrective Action Plan in Year One. The SDT believes this terminology is clear and understood. No change made.

Organization	Yes or No	Question 4 Comment
Independent Electricity System Operator	No	No. The process presented in Section III is overly prescriptive and requires information not necessary to the intended purpose.As state in Q1, we disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard, and propose alternate language as stated in Q1 comments.If this section must deal with a review of the use of footnote ‘b’/’12’ to ensure that there are no adverse reliability impacts on the bulk power system, then it should be limited to the information required for that purpose. Provided there is local support for the use of Non-Consequential Load Loss under footnote ‘b’/’12’, only information items 6 and 8 from section II are relevant for this assessment-the remainder are not required for this section and should be deleted.

Organization	Yes or No	Question 4 Comment
		As stated in Q2 above, the use of footnote ‘b’/’12’ shouldn not be limited to the Near-Term Planning Horizon. We propose that the words “in Year One of the Planning Assesssment”be deleted.Items 1 and 2 complicate this section and are unneccesary. They should be replaced by a phrase such as “for those planning events where the use of footnote ‘b’/’12’ is referenced”. We disagree with the need to submit to the ERO for a determination of whether there are any adverse reliability impacts caused by the use of Non-Consequential Load Loss. This will introduce a new type of review at the ERO that will create uneccesary delays and burden, and is inconsistent with and not required for all of the other performance requirements in the TPL standards. Submitting the analysis to the adjacent Planning Coordinators and Tranmission Planners, and any functional entity that requests it, as called for in requirement R8 of TPL001-2 should be sufficient.
Response: Please see the response to question 1. Please see the response to question 2. The remand Order made it clear that oversight was required for instances where use of footnote ‘b’ was proposed. The ERO is aware of the proposed responsibility and has accepted this role if the industry approves. The SDT believes that Requirement R8 of proposed TPL-001-2a is an important concept for sharing information and potentially resolving local differences, but it does not necessarily provide the wider area view that the ERO could provide. No change made.		
Midwest Independent Transmission System Operator, Inc.	No	No. MISO objects to a stakeholder process as outlined in Attachment 1. See our comments under Question 5.
Response: Please see response to question 5.		
Southwest Power Pool Reliability Standards Development Team	No	Section III is superfluous if the regulatory bodies are attending the open stakeholder process. This section should be removed due to the fact that if there is an issue or question on these events they should be addressed in the open stakeholder

Organization	Yes or No	Question 4 Comment
		meeting. Not sure why the team decided to add the ERO as an entity to check after the regulatory body has approved the use. We feel like if there needs to bee coordination between affected entities that they could participate in the open stakeholder process as well. You could add that they include possible affected entities to the invite list of the open meeting to discuss these footnote applications under section 1.
Response: The invitees to the stakeholder process should include all applicable entities and would be expected to include applicable regulatory bodies as shown. However, there is existing protocol for relationships between functional entities and regulatory bodies that goes beyond the extent of Section I and that is out of the purview of the SDT. That difference as well as the difference in Load levels between Sections I and III is what drove the SDT to produce the draft as posted. No change made. The remand Order made it clear that oversight was required for instances where use of footnote ‘b’ was proposed. The ERO is aware of the proposed responsibility and has accepted this role if the industry approves. No change made. The invitees to the stakeholder process should include all applicable entities and would be expected to include applicable regulatory bodies as shown. However, there is existing protocol for relationships between functional entities and regulatory bodies that goes beyond the extent of Section I and that is out of the purview of the SDT. That difference as well as the difference in Load levels between Sections I and III is what drove the SDT to produce the draft as posted. No change made.		
Western Area Power Administration	No	See answer to Question 1.
Platte River Power Authority	No	See answer to Question 1.
Florida Municipal Power Agency Lakeland Electric Gainesville Regional Utilities	No	See FMPA Comments regarding the 75 MW threshold of Question 1.

Organization	Yes or No	Question 4 Comment
Response: Please see response to question 1.		
NBSO	No	See our comments under Q2 and Q3, above.
Response: Please see responses to questions 2 and 3.		
Massachusetts Attorney General	No	The 75 MW and 25 MW limits do not belong there. It would be best if the limits were established by stakeholder consensus and by state rulemakings.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made.		
National Grid	No	The current document includes the language: 2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW.This gives no concept of how long customers could expect to be out of service and hence whether this would be an appropriate approach. Suggest using a value that is based on energy, i.e., MWh. A value of 600MWh would represent 25 MW out for 24 hours, or could be 60 MW out for 10 hours, etc. This would seem to provide a more valuable understanding the true impact to customers in assessing the health, safety and welfare. It is also expected that if Demand Resources are being used that they would be excluded from the term "non-consequencial" load, and that the value being discussed is only that in addition to any Demand Resources being used.
Response: The Section 1600 data request showed that entities were reporting footnote 'b' usage strictly in terms of MW. Therefore, the SDT decided to stay with existing terminology in this regard. In addition, duration is one of the factors required in Section II so the time element will be known to process participants. No change made. Upon reviewing the comments, the SDT has seen that Demand that is not included as Firm Demand for footnote 'b' could be clarified		

Organization	Yes or No	Question 4 Comment
as shown below. TPL-002-1c: footnote b) - ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load.		
Hydro One Networks Inc.	No	The process presented in Section III is overly prescriptive and duplicates information not necessary for its intended purpose.As stated in Q1, we disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard, and propose alternate language in our response to Q1.If this section is required to address a review of the use of footnote 12 to ensure that there are no wide-spread adverse reliability impacts on the bulk power system, then it should be limited to the information required for that purpose. Provided there is local support for the use of Non-Consequential Load Loss under footnote 12, only information items 6 and 8 from section II are relevant for this assessment-the remainder are not required for this section and should be deleted. Items 1 and 2 complicate this section and are unneccesary. They should be replaced by a phrase such as “for those planning events where the use of footnote 12 is referenced.” We disagree with the need to submit this information to the ERO for a determination of whether there are any Adverse Reliability impacts caused by the use of Non-Consequential Load Loss. This will introduce a new type of review at the ERO that will create uneccesary delays and burden, and is inconsistent with (and not required for) all of the other performance requirements in the TPL standards. Submitting the analysis to the adjacent Planning Coordinators and Tranmission Planners, and any functional entity that requests it, as called for in requirement R8 of TPL-001-2 should be sufficient.
Response: Please see the response to question 1. Items 1 and 2 place the constraints in the process that separate the less restrictive procedure outlined in Section I from the more		

Organization	Yes or No	Question 4 Comment
restrictive procedure in Section III. The suggested change would require the same level of review for any use of the footnote. The SDT does not believe that this is where the industry wants to go based on comments received. No change made. The remand Order made it clear that oversight was required for instances where use of footnote ‘b’ was proposed. The ERO is aware of the proposed responsibility and has accepted this role if the industry approves. Therefore, the SDT believes that there will not be any undue delays. The SDT believes that Requirement R8 of proposed TPL-001-2a is an important concept for sharing information and potentially resolving local differences, but it does not necessarily provide the wider area view that the ERO could provide. No change made.		
Ameren	No	The responses to the data request indicate that 33% of the respondents that use footnote “b” would drop 20 MW or less for single contingency events. Based on the data, we believe that the threshold for reporting should be 20 MW instead of 25 MW. As noted above in the response to item 1, we also believe that an upper limit of 40 MW should be established, again based on the responses to the data request. We find this proposed stakeholder process unique because we are inviting retail regulatory authorities to become involved in the compliance process for a handful of utilities now, but potentially for more in the future. We are unaware of any other standards where a state governmental agency is needed to grant permission for utilities to utilize certain aspects of the standard. We believe that this proposed process would potentially set a bad precedent, is not good policy for either the regulators or the transmission planners, and does not belong in a NERC standard.
Response: The SDT believes that the threshold selected is consistent with the data supplied in the data request within reasonable limits. No change made. Please see response to question 1. The SDT believes that the role provided to regulatory bodies is consistent with current practices in the industry today. While formal approval may not be provided by some regulatory bodies as pointed out in other comments, Section III does not require formal approval but rather a lack of dissent. No change made.		

Organization	Yes or No	Question 4 Comment
Arizona Public Service Company	No	The threshold of 25 MW in item 2 of section III is too low. It should be same as the maximum allowed value in foot note b. In addition, AZPS does not agree that no objection assurance by the Regional Entity should be required. Once the process has been fully vetted by the stakeholders, including the regulatory authority for retail service, there is absolutely no need for Regional Entity involvement. There would be no adverse affect of non-consequential load tripping on the BES. Hence no reason for Regional Entity involvement is needed.
Response: The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a least common denominator approach and would thus be rejected. No change made. The remand Order made it clear that oversight was required for instances where use of footnote 'b' was proposed. The ERO has been proposed as the best choice to provide such oversight. No change made.		
Manitoba Hydro	No	The word 'assure' should be 'ensure' in the opening paragraph of III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required.
Response: The SDT agrees and has made the change suggested. Section III, first paragraph: Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ~~assure~~ ensure that the applicable regulatory ~~authority~~ authorities or governing ~~body~~bodies responsible for retail electric service issues do~~es~~ not object to the use of Firm Demand interruption under footnote 'b' if either:		
ISO New England	No	This provision violates both the federal and state jurisdictional split over transmission facilities, and would violate several FERC orders directing the

Organization	Yes or No	Question 4 Comment
		independence of RTOs in the regional system planning process. Said another way, the determinations of a federal transmission planning entity may not be required through an ERO standard to be subject to non-jurisdictional review and approval by state entities. Further, the provision violates Section 215 of the Federal Power Act, as the ERO cannot require the review of a particular transmission system plan by state entities. The following language should therefore be deleted from Section III of Attachment 1: "Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Non-Consequential Load Loss under footnote 12... ." Overall, the order of Section III is also notable. During year, two through ten of the overall planning horizon the standard allows for Non-Consequential Load Loss without state approval. In the first year of the assessment, approval becomes required for Non-Consequential Load Loss. In year one, even if mandating state participation and decisional authority in a federal planning process was legally permissible, it is too late to allow for any other alternative as transmission planning, siting and construction of non-load loss alternatives would not be completed in the needed period. If there were non-load loss alternatives available, the use of non-consequential load loss would not be necessary, but it would also not be part of a transmission plan. The Regional Entities with NERC oversight perform periodic audits and require self-certification of the planning process. By virtue of the audit and self-certification process, NERC has the ability to monitor the use of Non-Consequential Load Loss in planning assessments. In addition to being notable for the year one timing, Section III seems incomplete. In the case where there is objection to Non-Consequential Load Shedding, the process appears to end without resolution. The submission to the ERO "for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss" conflcts with

Organization	Yes or No	Question 4 Comment
		federal law and orders of the Federal Energy Regulatory Commission. As noted above, the ERO is not a planning entity and does not have authority to displace the reliability planning performed by planning entities. Transmission planning entities are those directed by FERC to make the determinations regarding adverse reliability impacts. If any entity wishes to challenge those determinations, it may do so before FERC under Section 215 of the Federal Power Act. Further, this provision would conflict with orders of the FERC regarding the independence of RTOs to conduct the regional transmission planning process. A reliability standard may not change the scope or meaning of federal statutes nor may it contradict or collaterally attack orders of the Federal Energy Regulatory Commission. For these reasons, this provision should be removed from the attachment to the proposed standard.
Response: The SDT believes that the role provided to regulatory bodies is consistent with current practices in the industry today. The SDT does not believe that the footnote violates any regulations concerning transmission planning. The proposed process simply brings stakeholders including local regulators to the table in an open and transparent manner. No change made. While the requirement is not mandatory for use in a Corrective Action Plan until Year One, the SDT believes that it would be a good practice to move forward as soon as an entity knows it is contemplating usage of the footnote. And nothing in the document precludes such action. Since the applicable regulator would be at the table and would therefore see potential uses of the footnote prior to Year One, the stakeholder process provides the opportunity to get any potential timing issues out before they become a impediment. Furthermore, the remand Order made it clear that oversight was required for instances where use of footnote 'b' was proposed. This would imply that FERC does not believe that audit and self-certification is sufficient in this matter. No change made. The ERO is not participating in the planning process. The role of the ERO is restricted to a determination of whether the planned utilization of footnote 'b' will cause an Adverse Reliability Impact to the BES. The ERO has no further role in the transmission planning process beyond that determination. No change made.		
TVA Transmission Reliability Engineering and Controls	No	TVA believes that the requirements of 25 MW as well as any Bulk contingency over 300-kV is much too burdensome. TVA believes that only larger load drops (such as 50 MW and above) should require ERO review.
Response: The SDT believes that the threshold selected is consistent with the data supplied in the data request. Increasing the		

Organization	Yes or No	Question 4 Comment
threshold to 50 MW is not consistent with the data supplied and the SDT believes that such an action would be viewed as a non-acceptable least common denominator approach. No change made.		
Iberdrola USA	No	Why would a retail service regulator approve a 300 kV and above performance issue?
Response: The voltage level is not the significant issue; the significant issue is making certain that the regulator understands that the transmission plan is to shed Load for a single Contingency so that they can understand the implications of the proposed actions and properly evaluate other available alternatives.		
LCRA Transmission Service Corporation	No	
NB Power Transmission	No	
Response: Without specific comments, the SDT is unable to respond.		
Texas Reliability Entity	Yes	1. TRE requests clarification whether the 25 MW limit of Non-consequential Load Loss (Section III (2)) applies to a single contingency event for a specific Transmission Planner's region or to the entire Planning Coordinator area. For example, if a single contingency requires multiple Transmisson Planners to shed load, is each Transmission Planner allowed to drop up to 25 MW of load before requiring regulatory review? Or did the SDT intend to require the Transmission Planners/Planning Coordinator to submit the plan for regulatory review if the total load shed for the single contingency equals or exceeds 25 MW? 2. TRE feels that the requirement in Section III that the Planning Coordinator or Transmission Planner must submit information to the ERO for a determination of whether there are "any Adverse Reliability Impacts" is overly burdensome to industry, assuming that this refers to the new definition of "Adverse Reliability Impact" (limited to Instability and Cascading). It is extremely unlikely that any such impacts will result from application of this footnote, and any that might occur will

Organization	Yes or No	Question 4 Comment
		be identified in the stakeholder process. If the ERO determination step is retained, then a timeline should be included for completion of the ERO determination process.
Response: The footnote is written on a single Contingency basis so the latter instance of the comment is correct – the plan should be submitted if the total Load shed is greater than or equal to 25 MW. Such a determination may be considered unlikely but the SDT believes that the remand Order made it clear that oversight was required for instances where use of footnote ‘b’ was proposed. The ERO is aware of the proposed responsibility and has accepted this role if the industry approves. Therefore, the SDT does not believe that a timeline is required. No change made.		
California Independent System Operator	Yes	Despite a public consultation process that includes the regulator(s), the standard then calls for notification to the regulator(s) and only moving forward once the regulator indicates that it does not oppose the shedding of load (“once assurance has been received that...”). This is still requiring the regulator to do something, and could be problematic if no response is provided by the regulator. How would one address silence on the part of the regulator?
Response: The SDT believes that Sections I and III represent two separate and distinct instances of the process. In Section I, the regulator is just one of perhaps many interested and applicable parties. However, in Section III, where larger values of Load are involved, there is a more formal role for regulators to play. Each local situation is unique – in some there may be formal approval provided, in others just a lack of dissent. If the regulator is silent on the proposal, the entity can move forward with the plan. No change made.		
Lincoln Electric System	Yes	While supportive of Section III, LES believes the language in the last paragraph could be further enhanced with the following changes [located in brackets] to ensure a complete and accurate record is provided to the ERO."Once [written] assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Non-Consequential Load Loss under footnote 'b', the Planning Coordinator or Transmission Planner must submit the [written assurance and] information outlined

Organization	Yes or No	Question 4 Comment
		in items II.1 through II.8 above to the ERO...".
Response: The SDT does not believe it is appropriate to add 'written assurance' as the requirement only involves lack of dissent. No change made.		
Duke Energy	Yes	
SERC EC Planning Standards Subcommittee Associated Electric Cooperative	Yes	
Southern Company	Yes	
American Electric Power	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Deseret Generation & Transmission	Yes	
American Transmission Company	Yes	
Public Service Company of New Mexico	Yes	
Idaho Power Company	Yes	
SCE&G	Yes	
Georgia Transmission Corp	Yes	

Organization	Yes or No	Question 4 Comment
Response: Thank you for your support.		

5. If you have any other comments on this Standard that you haven't already mentioned above, please provide them here:

Summary Consideration: The comments supplied for question 5 are basically repetitive of what was stated for previous questions. Responses are provided consistent to what was stated above.

The following changes have been made due to industry comments:

TPL-002-1c: footnote b) - ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load.

Organization	Question 5 Comment
Independent Electricity System Operator	(1) We'd like to reiterate our support for allowing load interruption for a singlecontingency with sufficient review/oversight and under acceptable conditions, including no adverse impact on the reliability of the interconnected bulk power system. The reliability aspects (BES performance requirements) should be reviewed for acceptability by the adjacent Planning Coordinators and Transmission Planners. However, issues pertaining to economics or externalities which may not be directly reliability-related are always available for review and debate by the stakeholders via the regulatory processes and subject to approval by the regulatory authority of each jurisdiction (including those in Canada and Mexico). (2) Furthermore, we request that Table 1 of TPL-001-3 (previous TPL-001-2 approved by NERC BOT) be corrected for EHV contingencies in P2, P4 and P5 categories to allow the application of footnote 'b'/'12' that is allowed for the P1 events. Events in P2, P4, and P5 can involve more elements and can be more onerous and stressful to the system than the P1 events, and if use of footnote 'b'/'12' is permitted in the less stressful P1 events, it should also be permitted in P2, P4 and P5 events. (3) We suggest that NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve it. Accordingly, we believe that the focus of footnote 'b', and footnote 12 should be that interruption of load must not have an adverse impact on the reliability of the interconnected bulk power system. A continent-wide standard should not concern itself with the reliability of supply or supply continuity for local load, as that is the

Organization	Question 5 Comment
	responsibility of the applicable regulatory authority or its agencies responsible for local transmission and retail service over the load to be curtailed.As mentioned above, NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve it. In this regard, we believe that Attachment 1 is not necessary because it prescribes a process which goes beyond the outcome of the standard and dictates how stakeholdering must be carried out. The individual jurisdiction should establish the process for ensuring compliance with the standard and decide to what extent a stakeholdering process is necessary to establish the acceptable level of load rejection for the area in a manner consistent with local transmission established service levels.
Hydro One Networks Inc.	(1) We'd like to reiterate our support for allowing load interruption for a single contingency with sufficient review/oversight and under acceptable conditions, including no adverse impact on the reliability of the bulk electric system. The reliability aspects (BES performance requirements) should be reviewed for acceptability by the adjacent Planning Coordinators and Transmission Planners. However, issues pertaining to economics or externalities which may not be directly reliability-related are always available for review and debate by the stakeholders via the regulatory processes and subject to approval by the regulatory authority of each jurisdiction (particularly those in Canada and Mexico). (2) Furthermore, we request that Table 1 of TPL-001-2a (previous TPL-001-2 approved by the NERC BOT) be corrected for EHV contingencies in P2, P4 and P5 categories to allow the application of footnote 12 that is allowed for the P1 events. If a load is allowed to be interrupted for a single EHV transmission line contingency (Category P1), it should be allowed to interrupt the same load if the primary breaker fails (the event becomes category P4) and the fault is cleared by other breakers. Similarly, if the same breaker has an internal fault or there is a fault on the same bus section (Category P2) or there is a failure of a relay (Category P5), which results in the loss of the same EHV transmission line, it should be allowed to interrupt the same load. Events in P2, P4, and P5 can involve more elements and can be more onerouse and stressful to the system than the P1 events, and if use of footnote 12 is permitted in the less stressful P1 events, it must also be permitted in P2, P4 and P5 events. This issue has been raised by many entities in previous occasions and we believe the STD has not provided a convincing response.

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	(3) We suggest that NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve them. Accordingly, we believe that the focus of foot note 'b', and footnote 12 should be that interruption of load must not have a widespread, adverse impact on the reliability of the interconnected BES. A continent-wide reliability standard should not concern itself with the reliability of supply or supply continuity for local load, as that is the responsibility of the applicable regulatory authority or its agencies responsible for local transmission and retail service over the load to be curtailed. If NERC and/or FERC believe that MW threshold needs to be addressed within NERC Standard for US registered entities then the standard must clearly state that the requirement is for US registered entities only.
Response: (1) Thank you for your support. (2) Such discussion is out of scope for this project since TPL-001-2 has been approved by the industry through the standards development process and by the NERC Board of Trustees. Nothing in this project affects where footnote 12 is applied within Table 1. The only change being proposed is to the details of how to utilize footnote 12 as shown in the proposed Attachment 1. No change made. (3) FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand, and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. Canadian entities are allowed to adopt ERO Reliability Standards, reject them outright, or adapt them for their own use within the confines of provincial regulations. Nothing has changed in that regard with this proposed standard. No change made.	
Manitoba Hydro	(1) Effective Date section 5: The language used in the revision that was made is fine, however, where the language has been placed in the section is confusing. The language has been added to the end of the sentence that starts 'in those jurisdictions where regulatory approval is not required' and lumped those two concepts together. In our mind, there should be 3 separate concepts 1) where regulatory approval required 2) where regulatory approval not required and 3) as may otherwise be approved by applicable laws. (2) Corresponding changes do not appear to have been made, TPL 1 and TPL 2 are not consistent in terms of the language used in the Effective Date section or the Attachment 1 (the sections to

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	which changes were made since last circulation).
Response: (1) The language used in the effective date section is provided by NERC Legal and was designed to take into account the situations raised in the comment. No change made. (2) The SDT wishes to point out that the language may be slightly different due to the specific circumstances regarding definitions, etc., in the timeframe relevant to the two standards. However, the SDT believes that the language used in the two standards is consistent. Without specific references the SDT is unable to respond further. No change made.	
ACES Power Marketing Standards Collaborators	(1) The SDT needs to consider the connection between the developing standards to maintain and improve reliability with the costs required to meet those standards. We believe there is an imbalance of the costs associated with meeting compliance for the current draft standard with proposed benefit of maintaining reliability of the BPS. This standard is a good candidate for the CEAP initiative to determine the cost benefits of reliability. (2) The standard needs to allow more flexibility regarding the use of planned load shed to address transmission performance issues in the planning horizon. It needs to recognize that these planned load shedding events may only be preliminary decisions for addressing problems that are several years away. If there is little chance that the planned shed load will ever be relied upon in the operating time horizon, there should be much less stringent requirements. For instance, if a PC or TP relies on planned load shed for year five of the planning horizon but year one does not utilize the planned load shed, they have four years to develop another solution. Why should an entity expend great effort and resources for year five when another solution will likely be developed within that time period? (3) What does "materially changed" mean and what degree of a change would be considered material in the Attachment 1 stakeholder process? The SDT should clarify specific conditions in Section II that would constitute a material change. (4) Thank you for the opportunity to comment.
Response: (1) Cost factors are one of the elements in the list of criteria in Section II. Costs of different alternatives will be part of the information provided and rationales for selection or non-selection of alternatives should include consideration of costs. The CEAP	

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initiative is still a work in progress and will not be ready for use in the timeframe of this project. No change made. (2) The SDT agrees that more flexibility is needed in the longer term; therefore, in the Long-Term Transmission Planning Horizon the stakeholder process is not required, and its use is limited to the Near-Term Transmission Planning Horizon. However, the SDT believes that it is appropriate for planners to share future information in Section II so stakeholders are aware of any potential Load shed. No change made. (3) The SDT believes that the planning entity has the best understanding of when a change would become material. With the large range of design philosophies and geographic difference between the entities within NERC, it is not practical to adopt a single one size fits all approach. In addition, since the use of footnote 'b' will be a part of the entity's Corrective Action Plans, interested stakeholders will have the opportunity to question the continued use of footnote 'b'. No change made.	
Sacramento Municipal Utility District	1) The decision of necessary infrastructure addition versus a determination of load shed in lieu of costly transmission should be determined at the Public Utility Commission or Local Board of Directors not through a laod level limitation. 2) There are no impacts to the BES for load shedding actions where it is determined that it is confined to a set boundaryand demonstrate to not lead to cascading, uncrontrolled separation or blackout. 3) Where a concern that a stakeholder process be "gamed" to allow the unscrupulous entity to claim notification of affected stakeholders was followed should not dictate a continent-wide standard direction for other stakeholders.
Response: 1) FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. No change made. 2) The use of Footnote 'b' as proposed provides assurance that there is no Adverse Reliability Impact. No change made. 3) The conditions placed on the stakeholder process will provide consistency in the application of footnote 'b' on a continent-wide basis. No change made.	
Tri-State G&T	1. It is not clear how transmission projects with long lead times (such as T-lines) would be handled

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	by "Footnote b". In other words, it is not clear if it is acceptable for a TP to plan for shedding Firm Demand in the Near Term Planning Horizon without meeting the conditions shown in "Attachment 1" when a mitigating project is planned that cannot be constructed in the Near Term Planning Horizon. 2. NERC Functional Model definitions for Planning Authorities and Transmission Planners do not include the types of activities being proposed in "Attachment 1." As written, this standard mandates functions on functional entities that are outside those defined by the NERC Functional Model. 3. In the NERC Glossary of Terms, Interruptible Demand is defined as "Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment." The process described in Attachment 1 creates an agreement between stakeholders (aka "end-use customers") and their transmission providers for shedding Demand. Thus, if the process described in Attachment 1 is followed, the "Firm Demand" referenced in "Footnote b" would be reclassified as "Interruptible Demand." In essence, Firm Demand would not be interrupted. If this was the intention of FERC, NERC, and the Drafting Team, the standard should just state "Interruption of Firm Demand is not allowed." 4. It is not clear how section III of "Attachment 1" would be applied to entities that only deliver wholesale electric service and not retail electric service.

Response: 1. Any instance of proposed Load shed for a single Contingency situation in a Planning Assessment must meet the conditions of footnote 'b'. No change made.

2. The NERC Functional Model is a guideline for activities required of cited functional entities. It is periodically updated as conditions change. While the activities mentioned in the standard may not be explicitly spelled out in the NERC Functional Model, the SDT does not believe that they are out of scope for either a Planning Coordinator or a Transmission Planner. No change made.

3. Upon reviewing the comments, the SDT has seen that Demand that is not included as Firm Demand for footnote 'b' could be clarified as shown below.

TPL-002-1c: footnote b) - ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if it is~~: (1) Demand directly served by the Elements removed from service as a result of the

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Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load. 4. The SDT believes that the wholesale customer will be one of the stakeholders included in the process and any use of the footnote must go through the stakeholder process. No change made.	
MRO NSRF USACE MidAmerican Energy Company	1. In TPL-002-1c Table I and TPL-001-2a Table 1 can “Firm Demand interruption” or “Non-Consequential Load Loss” be initiated by a manual event such as operator action or does it need to be automatic? RECOMMENDATION: In TPL-002-1c Table I footnote ‘b’ add a sentence stating “Acceptable methods to enact Firm Demand Interruption may include manual or automatic processes that can be initiated within a reasonable timeframe”
Minnkota Power Cooperative Otter Tail Power Company	1. MPC QUESTION: In TPL-002-1c Table I and TPL-001-2a Table 1 can “Firm Demand interruption” or “Non-Consequential Load Loss” be initiated by a manual event, such as operator action, or does it need to be automatic, such as Under Voltage Load Shedding? a. RECOMMENDATION: In TPL-002-1c Table I footnote ‘b’, add a sentence stating “Acceptable methods to enact Firm Demand Interruption may include manual or automatic processes that can be initiated within a reasonable timeframe”
Response: Whether an action is automatic or manual is of no concern with regard to footnote ‘b’ as long as manual actions are executable within the time duration applicable to the Facility Ratings. No change made.	
California Independent System Operator	A concern with the new TPL-001-2 standard is what we see as being the elimination of the existing footnote c, the footnote that qualified Category C load shedding as “may be necessary”. The wording under the new TPL-001-2 appears that load shedding is the unqualified expectation of the criteria for C contingencies.
Response: The SDT clarified the expectations for the former Category ‘C’ Contingencies when it developed proposed TPL-001-2. TPL-001-2 was approved by the industry through the standards development process and by the NERC Board of Trustees. Nothing in this project affects where footnote 12 is applied within Table 1. The only change being proposed is to the details of how to utilize footnote 12 as shown in the proposed Attachment 1. Any discussions concerning the application of the footnote within the performance table are therefore out of scope for this project. No change made.	

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Iberdrola USA	A one-paragraph footnote encompassing a 2-page attachment is cumbersome for a Reliability Standard.
Response: The SDT made every effort to make the revisions required to be as simple as possible while meeting the requirements of the remand Order. No change made.	
BC Hydro and Power Authority	BC Hydro appreciates the efforts of the SDT in revising standards TPL-002-1c - System Performance Following Loss of a Single BES Element (footnote b) and TPL-001-2a - Transmission System Planning Performance Requirements (footnote 12). BC Hydro votes YES in support of this ballot and wishes to provide the following two comments:1.At this time BC Hydro has concerns about the level of stakeholder consultation that might be required as a result of the implementation of this standard and will bring this concern to the attention of our regulator if necessary. 2.At this time BC Hydro has concerns about the instances for which regulatory review of non-consequential load loss under footnote 12 is required and will discuss those with our regulator if necessary.
Response: 1. and 2. The SDT understands your situation and comment and appreciates your overall support.	
Hydro QuÃ©bec TransÃ‰nergie	Even if the SDT said it is not in its scope, the following difficulty with the application of note 12 needs to be addressed by NERC. There are no limit on non-consequential load loss for Single Contingency P2-2. and P2-3. (HV only), multiple Contingencies P4 and P5 (HV only), and P6 and P7. The note 12 allows limited non-consequential load loss for single contingency P1, Multiple Contingency P3. Non-consequential load loss is not allowed for P2-2 and P2-3. (EHV), and P4 and P5 (EHV). Considering the EHV Facilities, it is not reasonable to accept some non-consequential load loss for single contingency P1 and P2-3, and then deny it for Multiple Contingency categories P4 and P5 which are statistically less frequent than the former. Also, the Multiple Contingency P7 (for which there is no limit on non-consequential load loss) is more frequent than P2-3, P4 and P5. This technical irregularity must be reviewed and addressed.

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Northeast Power Coordinating Council	There are no limits on non-consequential load loss for Single Contingency P2-2 and P2-3 (HV only), multiple Contingencies P4 and P5 (HV only), and P6 and P7. Footnote 12 allows limited non-consequential load loss for single contingency P1, Multiple Contingency P3. Non-consequential load loss is not allowed for P2-2 and P2-3 (EHV), and P4 and P5 (EHV). Considering the EHV Facilities, it is not reasonable to accept some non-consequential load loss for single contingency P1 and P2-3, and then deny it for Multiple Contingency categories P4 and P5 which are statistically less frequent than the former. Also, the Multiple Contingency P7 (for which there is no limit on non-consequential load loss) is more frequent than P2-3, P4 and P5. This technical irregularity must be reviewed and addressed.
Response: TPL-001-2 was approved by the industry through the standards development process and by the NERC Board of Trustees. Nothing in this project affects where footnote 12 is applied within Table 1. The only change being proposed is to the details of how to utilize footnote 12 as shown in the proposed Attachment 1. No change made.	
Southern California Edison Company	Footnote "b"/Footnote 12 as currently written does not provide for an exemption to allow for the use of Firm Demand interruption as a short-term solution to transmission problems. Many entities would benefit from being allowed to use Footnote "b"/Footnote 12 as a temporary solution in response to construction delays until facilities to mitigate an N-1 contingency identified in a Planning Assessment can be installed. Under the current proposal, the stakeholder process will provide very little value in attempting to resolve such a problem. In fact, the current Footnote "b"/Footnote 12 could result in a stakeholder process that may actually slow the implementation of mitigation measures for the system.
Response: The SDT does not agree that the footnote does not provide for the use of Firm Demand interruption as a short-term solution to transmission problems. That has always been the point of the footnote and nothing in this project has changed that intent. The only changes are to the method in which the footnote is invoked. No change made.	
ISO New England	In summary, the main footnote is unobjectionable, but this standard as proposed has misplaced jurisdictional authority under Section 215 of the Federal Power Act for both states and the ERO through several of the process points and conditions set out in the attachment to the stardard. The removal of references is required for the standard to comport with the law. These revisions to

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	the standard can be made, which would then allow the draft standard to comply with FERC's further guidance and the other legal limitations described above.
Response: The SDT believes that the role provided to regulatory bodies is consistent with current practices in the industry today. The SDT does not believe that the footnote violates any regulations concerning transmission planning. The proposed process simply brings stakeholders including local regulators to the table in an open and transparent manner while setting criteria for when footnote 'b' can potentially be utilized. The ERO is not participating in the planning process. The role of the ERO is restricted to a determination of whether the planned utilization of footnote 'b' will cause an Adverse Reliability Impact to the BES. The ERO has no further role in the transmission planning process beyond that determination. No change made.	
Ameren	It might be helpful to probe further with the respondents who have no planned upgrades identified to address the dropping of non-consequential load to see what relevant system upgrades might entail, and the estimated costs associated with such upgrades, to address such situations.
Response: The SDT used the Section 1600 data request process to the best of its ability within the limited timeframe afforded to this project. No change made.	
LCRA Transmission Service Corporation	LCRA TSC disagrees with the October 2012 revision of TPL Table 1 Steady State & Stability Performance Footnotes (TPL-002-1c, footnote 'b' and TPL-001-2a footnote 12). The proposed stakeholder process required to be conducted during each Planning Assessment is overly burdensome. Further, it is not clear from the proposed process that a key concern expressed by the Commission with respect to use of Firm Demand load shedding is addressed - Notice to Firm Demand Customers. In addition, the proposed stakeholder process introduces several questions that need to be further clarified. For example: 1) Who defines the processes and procedures to be used? 2) Who is/are the decision maker(s)? 3) Who determines if the processes and procedures were followed?

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	4) Who carries out the administrative tasks (such as notice, securing meeting space,....)? 5) Who can participate? Does someone need to demonstrate a material interest in order to participate? 6) What are the means of participation (accepted forms of communication, timelines...)? 7) What are the criteria for decision-making? 8) What is the process for dispute resolution? How would does an Attachment become part of a NERC Standard? Should Attachment 1 be a requirement? In addition, support is needed for the bright-line 25 MW level. Lastly, the statement, "Before a Firm Demand interruption under footnote 'b' is allowed to be utilized as an element of a Corrective Action Plan in Year One of the Planning Assessment," implies that Firm Demand interruption may be used for years two through five of the Planning Assessment without the stakeholder process.

Response: Stakeholders representing the interests of Firm Demand customers would certainly be among the parties involved in Section I of the stakeholder process. No change made.

1) through 8) There is not a one-size-fits-all response to these questions for a continent-wide standard. The SDT provided the key components of an open and transparent stakeholder process while allowing variations that may be required due to differing structures and frameworks across the continent. Therefore, the answers to these questions may be different for each individual stakeholder process.

Attachments have been used in the past in other standards and are an accepted part of a standard.

The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote 'b' by planners. This data was then to be utilized by the SDT as part of its consideration in arriving at a maximum value for the amount of Load that could be planned to be shed under footnote 'b'. The 25 MW threshold was directly derived from this data. The SDT believes that any deviation from the threshold derived from the actual data may be viewed as a non-acceptable least common denominator approach. No change made.

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The SDT disagrees with the statement made by the commenter. Firm Demand interruption must go through the process for any year in the Near-Term Transmission Planning Horizon as is clearly stated in the main body of the footnote. No change made.	
TVA Transmission Reliability Engineering and Controls	Please see responses to question #2,3, and 4. TVA believes that only load drops of higher magnitudes go thru the Stakeholder and regulatory review.
Response: Please see responses to questions 2, 3, and 4.	
Public Utility District No.1 of Snohomish County MEAG Power City of Austin Clark Public Utilities	Public Utility District No.1 of Snohomish County generally disagrees with the October 2012 revision of TPL Table 1 Steady State & Stability Performance Footnotes (Planning Events and Extreme Events). "Footnote b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW.""Footnote 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed '75' MW."

Organization	Question 5 Comment
	The proposed revisions require that a Transmission Planner or Planning Coordinator provide assurance that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the interruptions of firm demand under TPL-002 footnote ‘b’ or TPL-001 footnote ‘12’ if the voltage level of the contingency is greater than 300 kV with certain sub-conditions or if the planned interruption of firm demand under these footnotes is greater than 25 MVA. In addition, under no case can planned Non-Consequential Load Loss exceed 75 MW.The magnitude and duration of load loss is a Level of Service (“LOS”) or Customer Service issue that is the jurisdiction of Public Utility Commissions and Local Electric Utility and Municipality boards. The boards and commissions represent their customers which often have diverse service and rate expectations that often are a result of local industry requirements, geography, urban/rural characteristics, and other factors of the particular service territory. Boards and commissions hold public meetings seeking input on various utility matters that often address services and rates. The rate impacts for customers are important; often more important than the service levels depending on the particular customer or customer class. Local boards and commissions are very close to these issues and weigh the input provided through public testimony to best represent their customer needs over the region they represent and have jurisdiction under state and local codes to address.The 75 MW Non-Consequential Load Loss threshold and the required NERC process do not resolve or address a reliability issue. The TPL footnotes address service requirements and should not be part of a NERC Reliability Standard any more than mandating specific System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI"). The Non-Consequential Load Loss requirement is an economic driven threshold that is not consistent throughout North America due to diverse customer needs and expectations. For instance, in some areas it may make economic sense and receive local approval to fund a $100 million system reinforcement to mitigate 1 in 20 year (5 percent chance of occurring) 76 MW Non-Consequential Load Loss exposure. However there are many communities that could not justify or support multi-million facilities to mitigate a 1 in 20 year event that may cause the Non-Consequential Load Loss of 76 MW of load. Public Utility District No.1 of Snohomish County supports removing the Non-Consequential Load Loss thresholds from the TPL Reliability Standards and allow the local boards and commissions to continue to address Customer Service Level issues as they are closest to the customers’ needs and have jurisdiction over this issue.

Organization	Question 5 Comment
Response: The SDT used the Board of Trustees approved standard as a starting point for this draft. FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. The proposed standards include the local regulatory bodies at every step in the process. This will allow those bodies to have input at every step. The SDT believes that the proposed changes to the standards are in alignment with the charge that was given to it. No change made.	
Xcel Energy	Setting limits on the amount of NCLL only sets the stage for failure in the compliance of NERC standards and fails to take note of what is really the issue; the planning of a transmission system that is both reliable and economically viable for all stakeholders and customers. It should be emphasized that the use NCLL in a "planning process" is only assuming the conditions set in the study will exist and in no way reflects the conditions seen during the day to day operation of the transmission system. Xcel Energy is concerned about the previous ability on loss of load in anticipation of the next outage (previously C3 now P6). For TPL-003, loss of load in anticipation of the next system outage was covered under footnote B. Footnote 9 now states, "...the re-dispatch does not result in any Non-Consequential Load Loss. " This is a large increase in requirements of the transmission system to operate. As written, it appears that footnote 12 is NOT applicable to P6 contingencies. Please clarify is this is the intent.
Response: The SDT does not believe that it needs to add language emphasizing that there is a difference between planning and operations when these standards are clearly planning standards. No change made. The SDT disagrees that there was a previous ability to shed Load in anticipation of the next Contingency. Footnote 'b' only allowed curtailment of firm transfers in preparation for the next Contingency. In addition, footnote 12 is not applicable for P6 planning events since Non-Consequential Load loss is allowed. No change made.	
Arizona Public Service Company	The following comment relates to Table 1. It is not clear why footnote 12 applies only to P2-1. The events P2-2, P2-3, P4, P5 are much less probable and the footnote 12 should be applicable to all these events. Why is that loss of non-consequential load is allowed for line tripping without fault but not for a bus fault which is much less likely and could result into same line trip. Similar

Organization	Question 5 Comment
	arguments apply to other scenarios listed above.
Response: TPL-001-2 was approved by the industry through the standards development process and by the NERC Board of Trustees. Nothing in this project affects where footnote 12 is applied within Table 1. The only change being proposed is to the details of how to utilize footnote 12 as shown in the proposed Attachment 1. Any discussions concerning the application of the footnote within the performance table are therefore out of scope for this project. No change made.	
Electric Reliability Council of Texas, Inc.	The SDT is not required to utilize the stakeholder approach by Order 762 or any other relevant FERC orders. FERC merely provided guidance as to how the rejected proposal could be improved. However, if the SDT elects to pursue an exception process, such exceptions should be based on objective criteria, and the process should be external to the NERC Reliability Standards (e.g. in the Rules of Procedure).In Order 693, FERC directed NERC to clarify footnote (b) to prohibit shedding firm load except for consequential load loss (Order 693 at PP 1773, 1794 and 1797}. In a related compliance order, FERC reaffirmed its position. (130 FERC 61,200 (March 18, 2010) at PP 8-10 (Compliance Order)) In a subsequent order, FERC clarified that its Order 693 directive did not preclude consideration of specific comments related to planning the system based on load shedding at the “fringes" of a system. (131 FERC 61,231 (June 11, 2010) at P 21 (Clarification Order)) FERC held that regional variances for case-specific circumstances or a case-specific exception process to plan for the loss of firm service “at the fringes of various systems" would be acceptable. (131 FERC 61,231 (June 11, 2010) at P 21 (Clarification Order)) However, FERC also stated that it viewed the basis for such exceptions as economic, not reliability, with the justification being that it was not economic to invest in the bulk electric system to serve all non-consequential load customers under some single contingency conditions. (Order 693 at P 1792) FERC made clear that any such regional differences or case specific exception processes cannot reflect the lowest common denominator, and, they must be technically justified, and such justification must be strong. (Clarification Order at P 21, See also Order 693 at P 1794) This is consistent with FERC's position that this is a matter of "fundamental issue of transmission service". (Order 693 at P 1793) In recognizing that meeting firm demand under single contingency conditions is fundamental to transmission service, FERC noted that NERC's definition of firm transmission service is the "highest quality (priority) service offered to customers ... that anticipates no planned interruption." (Order 693 at P 1793)Against this background, NERC filed

Organization	Question 5 Comment
	revisions to footnote b that allowed transmission plans to shed non-consequential load under single contingency conditions, provided appropriate process applied to such planning determinations/outcomes. In Order No. 762, {139 FERC 11 61,060 (April 19, 2012)) FERC rejected the approach proposed by NERC and provided guidance on acceptable approaches to footnote b. However, FERC did not endorse or mandate any particular approach. Rather, it merely urged "NERC to develop in a timely manner an appropriate modification that is responsive to the Commission's directives in Order No. 693 and our concerns set forth in this Final Rule." (Order 762 at P21) FERC stated that in order for any such proposal to have merit, it must be technically justified and must not reflect the lowest common denominator.As discussed, the proposed stakeholder approach is not appropriate for NERC Reliability Standards. The SDT should abandon that approach and consider simple revisions to footnote b that reference a case by case exception process based on objective criteria that is external to the NERC Reliability Standards (e.g. Rules of Procedure). Alternatively, it should develop revisions to the continent-wide standards that clarify that non-consequential load shedding is not generally permitted for single contingency conditions, but, consistent with FERC's orders, exceptions could be established pursuant to regional rules based on the need/appropriateness in a particular region.Consistent with the above discussion, if the SDT elects to pursue revisions that accommodate shedding non-consequential load in transmission planning for single contingency conditions, it should abandon the stakeholder process approach. The establishment of exceptions is better suited for regional rules or pursuant to a process outside of the reliability standards - e.g. via the Rules of Procedure, because such a process is not suited for a continent-wide reliability standard. Regardless of whether the issue is addressed via an external process, or left to regional variances, this issue needs to be addressed in a relatively timely manner because the uncertainty is affecting planning processes.

Response: FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. The SDT has set up criteria for consideration in the potential usage of footnote ‘b’ for planning purposes in Attachment 1, Section II, Bullets 1 through 8. The criteria described are objective. The process described does not tell a entity how to go about its business but only describes what must be done to allow for the usage of footnote ‘b’ in the planning process. The SDT believes that the referenced exception process is what is being proposed. The proposed process sets up an open and transparent process for allowing such Load shed in

Organization	Question 5 Comment
specific conditions and with specific limitations. Any future revisions to footnote 12 will be accomplished through the approved standards development process and any discussion on changing threshold values would be part of that process. No change made.	
Midwest Independent Transmission System Operator, Inc.	We do not support using a stakeholder process to determine if Non-conseqeuntial Load Loss is appropriate following a single contingency event as a means to satisfy the standard. Stakeholder processes will nearly always result in disagreements. The parties that may be responsible for payment of upgrade costs will not necessarily line up with the parties adversely impacted by the alternative load loss. If the stakeholder process includes all stakeholders, there may be many more stakeholders impacted by upgrade costs based on broader benefits and/or cost sharing than stakeholders impacted by the alternative load loss. This will result in the majority decision of a stakeholder body to most often be one that supports load shed (until it is their turn to be the load that is shed). On the other hand, if the stakeholder process is limited to only the stakeholders directly impacted by the proposed load shed, to the extent those stakeholders pay only a small part of the upgrade costs, they will always select a potentially costly upgrade to avoid load shed. The point is, we do not believe that it possible to have a fair and impartial stakeholder process to correctly determine if and when load shed is acceptable to assist in satisfying a single contingency standard. Since the general intents of the existing TPL-002-1 standard and proposed TPL-001-2 standard are not to rely on any shedding of non-consequenital load to meet a single contingency event, in the event that footnote b of TPL 002-1 or footnote 12 of TPL 001-2 is not eliminated, we believe that it should be narrowly focused only on those situations for which the original footnote was developed: interruption of service to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, where the overall reliability of the interconnected transmission system is not impacted. We propose that footnote b and footnote 12 be modified as follows to ensure it is not misapplied:"An objective of the planning process is to avoid Non-Consequential Load Loss following Contingency events. In limited circumstances, Non-Consequential Load Loss may be needed within the planning horizon to ensure that BES performance requirements are satisfied. However, Non-consequential Load Loss cannot be used to avoid cascading outages or to maintain system stability. Non-consequential Load Loss also cannot be used to avoid a thermal loading or voltage limit violation on an EHV facility. When Non-Consequential Load Loss is utilized within the planning horizon to address BES performance requirements, such interruption cannot exceed 75 MW and is limited to the

Organization	Question 5 Comment
	following circumstances: o Non-consequential Load Loss is allowed for load served by a radial transmission line to avoid voltage limit violations on the radial transmission line following a single contingency event anywhere on the system.. o Non-consequential load shed is allowed for load within a local area served by not more than two transmission lines and/or transformers to avoid a thermal loading issue or voltage issue in the local area, including the transmission lines and/or transformers supplying the area, for a loss of one of the transmission lines or transformers supplying the area, so long as there are no thermal loading or voltage violations outside the local area."We believe the language above maintains acceptable reliability on the bulk electric system by limiting load shed and violations that require load shed to radial areas or areas that would be served radially following the single contingency. We therefore highly recommend that Attachment I be eliminated entirely and that the footnotes either be eliminated or replaced with the modified version above.
Response: FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. No change made.	
SCE&G	While the current revisions improve the processes described, we have concerns regarding the revisions to TPL002-1 b. SCE&G has significant concern with the proposed revision to TPL Table 1, Footnote B. The current Footnote B states "Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems". The phrase "without impacting the overall reliability of the interconnected transmission systems" is important to the TPL standards to ensure that ERO standards do not dictate the level of service to specific customers. Service to specific customers and load pockets is jurisdictional to State Commissions. ERO standards should not compromise this jurisdiction. SCE&G believes that any proposed revisions to Footnote B must maintain the concept that planned or controlled interruption of electric supply to customers, whether they are radial or network, is allowed as long as it does not impact the overall reliability of the interconnected transmission systems. The proposed revision eliminates this concept

Organization	Question 5 Comment
Response: The SDT believes that the suggested wording is redundant as the quoted statement is the basis for standards activities. No change made.	

END OF REPORT

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR approved by SC in May 2012.
2. Initial comment period July 31, 2012 – August 29, 2012.
3. Initial ballot and comment period October 5, 2012 – November 19, 2012.

Proposed Action Plan and Description of Current Draft:

The SDT is working to address FERC's remand of the proposed clarification of TPL-002, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System. That footnote is captured here as footnote 12.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Successive ballot	December 2012
2. Recirculation ballot	January 2013
3. BOT approval	February 2013

Definitions of Terms Used in Standard

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

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

A. Introduction

1. **Title: Transmission System Planning Performance Requirements**

2. **Number: TPL-001-2a**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-2a:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.

- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past

studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the

use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

<table>
<tr><th>Category</th><th>Initial Condition</th><th>Event [1]</th><th>Fault Type [2]</th><th>BES Level [3]</th><th>Interruption of Firm Transmission Service Allowed [4]</th><th>Non-Consequential Load Loss Allowed</th></tr>
<tr><td rowspan="2">P3
Multiple Contingency</td><td rowspan="2">Loss of generator unit followed by System adjustments[9]</td><td>Loss of one of the following:
1. Generator
2. Transmission Circuit
3. Transformer [5]
4. Shunt Device [6]</td><td>3Ø</td><td rowspan="2">EHV, HV</td><td rowspan="2">No[9]</td><td rowspan="2">No[12]</td></tr>
<tr><td>5. Single pole of a DC line</td><td>SLG</td></tr>
<tr><td rowspan="3">P4
Multiple Contingency
(Fault plus stuck breaker[10])</td><td rowspan="3">Normal System</td><td rowspan="2">Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following:
1. Generator
2. Transmission Circuit
3. Transformer [5]
4. Shunt Device [6]
5. Bus Section</td><td rowspan="2">SLG</td><td>EHV</td><td>No[9]</td><td>No</td></tr>
<tr><td>HV</td><td>Yes</td><td>Yes</td></tr>
<tr><td>6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus</td><td>SLG</td><td>EHV, HV</td><td>Yes</td><td>Yes</td></tr>
<tr><td rowspan="2">P5
Multiple Contingency
(Fault plus relay failure to operate)</td><td rowspan="2">Normal System</td><td rowspan="2">Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following:
1. Generator
2. Transmission Circuit
3. Transformer [5]
4. Shunt Device [6]
5. Bus Section</td><td rowspan="2">SLG</td><td>EHV</td><td>No[9]</td><td>No</td></tr>
<tr><td>HV</td><td>Yes</td><td>Yes</td></tr>
<tr><td rowspan="2">P6
Multiple Contingency
(Two overlapping singles)</td><td rowspan="2">Loss of one of the following followed by System adjustments.[9]
1. Transmission Circuit
2. Transformer [5]
3. Shunt Device[6]
4. Single pole of a DC line</td><td>Loss of one of the following:
1. Transmission Circuit
2. Transformer [5]
3. Shunt Device [6]</td><td>3Ø</td><td>EHV, HV</td><td>Yes</td><td>Yes</td></tr>
<tr><td>4. Single pole of a DC line</td><td>SLG</td><td>EHV, HV</td><td>Yes</td><td>Yes</td></tr>
</table>

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State	Stability
1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments. 2. Local area events affecting the Transmission System such as: a. Loss of a tower line with three or more circuits.[11] b. Loss of all Transmission lines on a common Right-of-Way[11]. c. Loss of a switching station or substation (loss of one voltage level plus transformers). d. Loss of all generating units at a generating station. e. Loss of a large Load or major Load center. 3. Wide area events affecting the Transmission System based on System topology such as: a. Loss of two generating stations resulting from conditions such as: i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation. ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances.	1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments. 2. Local or wide area events affecting the Transmission System such as: a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing. e. 3Ø internal breaker fault. f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. 2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. 3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss. 4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. 5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. 6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground. 7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point. 8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker. 9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. 10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing. 11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less. 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW. 13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community

3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

<u>III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required</u>

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues does not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW.

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues does not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	03/17/2001	Revision of TPL-001-0 to modify only Table 1 footnote b. Approved by Board of Trustees	Project 2006-02 – revision to address FERC directive
2	To be Determined	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2a	February 2013	Address remand of proposed footnote 'b' pursuant to FERC Order RM06-16-009	Revised

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR approved by SC in May 2012.
2. Initial comment period July 31, 2012 – August 29, 2012.
~~2.~~3. Initial ballot and comment period October 5, 2012 – November 19, 2012.

Proposed Action Plan and Description of Current Draft:

The SDT is working to address FERC's remand of the proposed clarification of TPL-002, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System. That footnote is captured here as footnote 12.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. ~~Initial~~Successive ballot	~~October~~ December 2012
2. Recirculation ballot	~~December 2012~~January 2013
3. BOT approval	February 2013

Definitions of Terms Used in Standard

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

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-2a**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where ~~-~~regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-2a:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.

- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past

studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the

use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity’s individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
      ii. Loss of the use of a large body of water as the cooling source for generation.
      iii. Wildfires.
      iv. Severe weather, e.g., hurricanes, tornadoes, etc.
      v. A successful cyber attack.
      vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
   b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   e. 3Ø internal breaker fault.
   f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following ~~Contingency~~ planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

b. ~~Assessment~~An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community

3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to ~~mitigate~~alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ~~assure~~ ensure that the applicable regulatory ~~authority~~authorities or governing ~~body~~bodies responsible for retail electric service issues does not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW.

Once assurance has been received that the applicable regulatory ~~authority~~authorities or governing ~~body~~bodies responsible for retail electric service issues does not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	03/17/2001	Revision of TPL-001-0 to modify only Table 1 footnote b. Approved by Board of Trustees	Project 2006-02 – revision to address FERC directive
2	To be Determined	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2a	February 2013	Address remand of proposed footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Implementation Plan for TPL-001-2a

Prerequisite Approvals

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

TPL-001-2a — Transmission System Planning Performance Requirements

In revising the TPL standards, the SDT is assuming that planners will receive valid data from the MOD standards link described in TPL-001-2a, Requirement R1. Furthermore, there is a tacit assumption that future revisions of the MOD standards will include steps to validate MOD based data.

Revision to Sections of Approved Standards and Definitions

There are multiple new definitions in the proposed standard.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Compliance with Standards

Standard	Functions That Must Comply With the Associated Requirements	
TPL-001-2a — Transmission System Planning Performance Requirements	Transmission Planner	Planning Coordinator
	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-2a:

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

TPL-001-1a, TPL-002-1c, TPL-003-1b, and TPL-004-1a are being retired as they are replaced in their entirety by TPL-001-2a. TPL-005-0 and TPL-006-0.1 are being retired because their requirements are adequately covered by the revised TPL-001-2a and NERC's Rules of Procedure, Section 800. TPL-001-1a, TPL-002-1c, TPL-003-1b, TPL-004-1a, TPL-005-0 and TPL-006-0.1 are being retired on midnight of the day immediately prior to the Effective Date of TPL-001-2a in the particular jurisdictions in which TPL-001-2a is becoming effective. However, during this 24-month period, all aspects of TPL-001-1a through TPL-006-0.1 shall remain in effect for compliance monitoring. This 24 month period is to allow entities to develop, perform and/or validate new and/or modified studies, methodologies, assessments, procedures, etc. necessary to implement and meet the TPL-001-2a requirements. The specified effective dates are expected to allow sufficient time for proper assessment of the available options necessary to create a viable Corrective Action Plan that is compliant with the new Standard.

R1. This Requirement is related to maintaining System models and the data needed to do so. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

R7. This Requirement identifies an obligation to determine individual and joint responsibilities for performing studies needed to do the Planning Assessment. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes

into effect   on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

TPL-001-2a 'raises the bar' in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-1a, TPL-002-1c, TPL-003-1b and TPL-004-1a because loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by many to allow such actions. As shown in Table 1 of TPL-001-2a, the performance requirements associated with the following events represent "raising the bar":

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

This "raising the bar" is beyond the control of the Transmission Planner and Planning Coordinator and may have significant budget, siting, permitting, and construction impacts on many Transmission Owners. To provide stakeholders with sufficient time to implement changes, a timeframe coincident with the end of the Near-Term Transmission Planning Horizon has been provided

Any entity which cannot eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for these performance elements by that date shall submit a mitigation plan to its Regional Entity outlining the steps it will take to correct the problem. If the entities follow the established ERO procedure for mitigation, it is the intent of the SDT that no penalties will be assessed.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR approved by SC in May 2012.
2. Initial comment period July 31, 2012 – August 29, 2012.
3. Initial ballot and comment period October 5, 2012 – November 19, 2012

Proposed Action Plan and Description of Current Draft:

The SDT is working to address FERC's remand of the proposed clarification of TPL-002, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System. Table 1 appears in the first four of the current TPL standards but footnote 'b' only applies to TPL-002. Therefore, only TPL-002 is being posted for industry comment at this time. When the footnote has been approved, all four of the applicable TPL standards will be filed with the Commission.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Successive ballot	December 2012
2. Recirculation ballot	January 2013
3. BOT approval	February 2013

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-1c

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised
1c	February 2013	Address remand of proposed footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. For purposes of this footnote, the following are not counted as Firm Demand t: (1) Demand directly served by the Elements removed from service as a result of the Contingency, and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 'b' is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Firm Demand interruption under footnote 'b'
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote 'b' (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote 'b' which must include the following:

1. Conditions under which Firm Demand interruption under footnote 'b' would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Firm Demand MW to be interrupted with:
    a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community
3. Estimated frequency of Firm Demand interruption under footnote ‘b’ based on historical performance
4. Expected duration of Firm Demand interruption under footnote ‘b’ based on historical performance
5. Future plans to alleviate the need for Firm Demand interruption under footnote ‘b’
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote ‘b’
8. Assessment of potential overlapping uses of footnote ‘b’ including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Interruptions of Firm Demand under Footnote ‘b’ is Required

Before a Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote ‘b’ if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote ‘b’, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote ‘b’ is greater than or equal to 25 MW

In no case can the planned Firm Demand interruption under footnote ‘b’ exceed 75 MW.

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote ‘b’, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR approved by SC in May 2012.
2. Initial comment period July 31, 2012 – August 29, 2012.
3. ~~2.~~Initial ballot and comment period October 5, 2012 – November 19, 2012

Proposed Action Plan and Description of Current Draft:

The SDT is working to address FERC's remand of the proposed clarification of TPL-002, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System. Table 1 appears in the first four of the current TPL standards but footnote 'b' only applies to TPL-002. Therefore, only TPL-002 is being posted for industry comment at this time. When the footnote has been approved, all four of the applicable TPL standards will be filed with the Commission.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. ~~Initial~~Successive ballot	~~October~~ December 2012
2. Recirculation ballot	~~December 2012~~January 2013
3. BOT approval	February 2013

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-1c

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition
1b	April 2010	Revised footnote 'b' pursuant to FERC Order RM06-16-009.	Revised
1c	February 2013	Address remand of proposed footnote 'b' pursuant to FERC Order RM06-16-009	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. ~~It is recognized that Firm~~ For purposes of this footnote, the following are not counted as Firm Demand ~~will be interrupted if itt is~~: (1) Demand directly served by the Elements removed from service as a result of the Contingency, ~~or~~and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote ‘b’ is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Firm Demand interruption under footnote ‘b’
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote ‘b’ (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote ‘b’ utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote ‘b’ which must include the following:

1. Conditions under which Firm Demand interruption under footnote ‘b’ would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Firm Demand MW to be interrupted with:
    a. The estimated number and type of customers affected

   b. ~~Assessment~~ An explanation of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community
3. Estimated frequency of Firm Demand interruption under footnote ‘b’ based on historical performance
4. Expected duration of Firm Demand interruption under footnote ‘b’ based on historical performance
5. Future plans to ~~mitigate~~ alleviate the need for Firm Demand interruption under footnote ‘b’
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote ‘b’
8. Assessment of potential overlapping uses of footnote ‘b’ including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Interruptions of Firm Demand under Footnote ‘b’ is Required

Before a Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ~~assure~~ensure that the applicable regulatory ~~authority~~ authorities or governing ~~body~~bodies responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote ‘b’ if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote ‘b’, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote ‘b’ is greater than or equal to 25 MW

In no case can the planned Firm Demand interruption under footnote ‘b’ exceed 75 MW.

Once assurance has been received that the applicable regulatory ~~authority~~ authorities or governing ~~body~~bodies responsible for retail electric service issues does not object to the use of Firm Demand interruption under footnote ‘b’, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by “study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies).” 2. “…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).” 3. “Include the effects of existing and planned protection systems, including any backup or redundant systems.” *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as “A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.”
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations. This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

Implementation Plan for Project 2010-11: TPL Table 1 Order

Prerequisite Approvals

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

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed standards.

Compliance with Standards

Standards	Functions That Must Comply With the Associated Requirements	
	Transmission Planner	Planning Authority
TPL-001-1: System Performance Under Normal (No Contingency) Conditions (Category A) TPL-002-1c: System Performance Following Loss of a Single Bulk Electric System Element (Category B) TPL-003-1: System Performance Following Loss of Two or More Bulk Electric System Elements (Category C) TPL-004-1: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other

requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective.

All other requirements remain in effect as per previous approvals.

Project 2010-11 Revision of TPL-002 footnote 'b' and TPL-001 Footnote 12

Unofficial Comment Form

Please **DO NOT** use this form for submitting comments. Please use the electronic form located at the link below to submit comments on the Standard. The electronic comment form must be completed by 8:00 p.m. ET, **January 11, 2013**.

If you have questions, please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Project page

Background Information

This posting is soliciting formal comment.

FERC Order No. 762 issued April 19, 2012 remanded TPL-002-1b as vague, unenforceable, and not responsive to the previous Commission directives on this matter. The Standards Committee directed the Standards Drafting Team (SDT) to revise footnote 'b' in accordance with the directives of Orders No. 693 and 762. The SDT was also charged with revising the corresponding footnote 12 of TPL-001-2 in order to prevent the remand of TPL-001-2.

The NERC Board of Trustees approved version of TPL-002-1b was used as a starting point for these deliberations. This was done because when FERC remanded the standard it was not because it contained a stakeholder process, but because the stakeholder process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand, and did not assure that BES reliability would be maintained. Thus, the initial balloted draft was designed to respond to those criticisms by adding the necessary detail and specificity to the already approved approach.

TPL-001-2 has been approved by the industry through the standards development process and by the NERC Board of Trustees. The Standards Authorization Request (SAR) for this project recognized this fact and thus did not allow for any changes to the utilization of footnote 12. Nothing in this project changes the application of footnote 12 within Table 1 of TPL-001-2.

The remand order from FERC requested that a Section 1600 data request be made to provide data on the actual usage of footnote ‘b’ by planners. The SDT utilized the data received in reaching its determination of the threshold values applied in the footnote and believes that the data request results provide a sufficient technical rationale for the threshold values. Furthermore, the SDT believes that any deviation from the thresholds derived from the actual data may be viewed as unacceptable in addressing the directives in Orders .

The proposed stakeholder process does not eliminate or reduce the role of local regulatory authorities, nor does it impose on local regulatory proceedings. The proposed stakeholder process was designed to incorporate an open and transparent proceeding to the potential utilization of footnote ‘b’ with all affected parties involved in the discussions. Local regulatory authorities are still free to perform their legislative mandates.

The SDT has made a number of clarifying changes to the footnote and Attachment based on comments received from the initial ballot posting. These changes include clarifying that Consequential Load Loss and Demand-Side Management programs are not affected by application of the footnote. The questions in this comment form are restricted to these changes. There have been no changes to the Implementation Plan originally filed with the respective standards.

The SDT requests that commenters refrain from repeating comments submitted in the previous posting. The SDT has noted those comments and responded to them to the best of its ability within the project constraints.

You do not have to answer all questions. Enter All Comments in Simple Text Format. Bullets, numbers, and special formatting will not be retained.

Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree with changes made to the body of the footnote? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes

☐ No

Comments:

2. Do you agree with the changes contained in Section II of Attachment 1? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes
☐ No
Comments:

3. Do you agree with changes contained in Section III of Attachment 1? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes
☐ No
Comments:

4. If you have any other comments on this Standard that you haven't already mentioned above, and that are not simply reiterating previous comments that the SDT has already responded to, please provide them here:

Comments:

Standards Announcement

Project 2010-11– TPL Table 1 Order
TPL-002-1c, footnote ‘b’ and TPL-001-2a, footnote 12

Successive Ballot is now open through Friday, January 11, 2013

Now Available

A successive ballot is now open for revisions to a single footnote that is incorporated into two standards (**TPL-002-1c**– System Performance Following Loss of a Single BES Element for footnote ‘b’, and **TPL-001-2a** – Transmission System Planning Performance Requirements for footnote 12) through **8 p.m. Eastern Friday, January 11, 2013.**

Please note that, aside from the proposed revisions to the footnote and changes to conform the Enforcement Dates section to the current language approved by NERC legal to cover all of the jurisdictions in which NERC standards are mandatory, no other revisions have been made to either standard. The scope of the drafting team’s assignment is limited to addressing changes to the single footnote.

Instructions

Members of the ballot pools associated with this project may log in and submit their vote for the footnote by clicking here.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and successive ballot and, if needed, make revisions to the footnote. If the comments do not show the need for significant revisions, the footnote will proceed to recirculation ballot.

As a reminder, the drafting team will hold a webinar to review the revisions on Tuesday, January 8, 2013, from 1:00 to 3:00 p.m. Eastern. Please click here to register for this webinar.

Background

FERC Order No. 762, issued April 19, 2012, remanded TPL-002-0b to NERC as vague, unenforceable and not responsive to the previous Commission directives on this matter. The Standards Committee directed the Standards Drafting Team (SDT) to revise footnote ‘b’ in accordance with the directives of

Orders No. 693 and 762. The SDT was also charged with revising the corresponding footnote 12 of TPL-001-2 in order to prevent the remand of TPL-001-2.

In revising the footnotes, the SDT adopted a philosophy of minimal changes to the actual footnote itself. This was done to minimize confusion as to what was changed, for ease of reading and following the footnote, and for formatting within the actual standards documents. Instead, the SDT revised the footnote by developing an attachment to the footnote containing changes in response to the Commission orders. It should be noted that attachments to standards are an extension of the Requirements and thus are binding to applicable entities.

Project 2010-11 is an important part of the ERO's strategic goal to be responsive to regulatory authority directives in an expeditious manner in order to reduce the amount of standards-related directives and to provide an adequate level of reliability.

Additional information can be found on the project page.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Development Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2010-11– TPL Table 1 Order
TPL-002-1c, footnote ‘b’ and TPL-001-2a, footnote 12

Formal Comment Period: December 10, 2012 – January 11, 2013

Upcoming:
Successive Ballot: January 2, 2013 – January 11, 2013

Now Available

A 30-day formal comment period and successive ballot is open for revisions to a single footnote that is incorporated into two standards (**TPL-002-1c**– System Performance Following Loss of a Single BES Element for footnote ‘b’, and **TPL-001-2a** – Transmission System Planning Performance Requirements for footnote 12) through **8 p.m. Eastern Friday, January 11, 2013.**

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Instructions for Commenting

A formal comment period on the single footnote that is incorporated into **TPL-002-1c** and **TPL-001-2a** is open through **8 p.m. Eastern on Friday, January 11, 2013.** Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

The drafting team will hold a webinar to review the revisions on Tuesday, January 8 from 1:00 to 3:00 p.m. Eastern. Registration instructions for this webinar will be provided in a separate announcement.

The drafting team will consider all comments received during the formal comment period and successive ballot and, if needed, make revisions to the footnote. If the comments do not show the need for significant revisions, the footnote will proceed to recirculation ballot.

Background

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TPL-002-1c, footnote ‘b’ and TPL-001-2a, footnote 12

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The drafting team will consider all comments received during the formal comment period and successive ballot and, if needed, make revisions to the footnote. If the comments do not show the need for significant revisions, the footnote will proceed to recirculation ballot.

Background

FERC Order No. 762, issued April 19, 2012, remanded TPL-002-0b to NERC as vague, unenforceable and not responsive to the previous Commission directives on this matter. The Standards Committee directed the Standards Drafting Team (SDT) to revise footnote 'b' in accordance with the directives of Orders No. 693 and 762. The SDT was also charged with revising the corresponding footnote 12 of TPL-001-2 in order to prevent the remand of TPL-001-2.

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Standards Announcement

Project 2010-11– TPL Table 1 Order
TPL-002-1c, footnote ‘b’ and TPL-001-2a, footnote 12

Successive Ballot Results

Now Available

A successive ballot window for revisions to a single footnote that is incorporated into two standards (**TPL-002-1c**– System Performance Following Loss of a Single BES Element for footnote ‘b’, and **TPL-001-2a** – Transmission System Planning Performance Requirements for footnote 12) concluded at **8 p.m**. **Eastern on Friday, January 11, 2013.**

Voting statistics for each ballot are listed below, and the Ballot Results page provides a link to the detailed results.

Approval
Quorum: 85.47% Approval: 65.77%

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the footnote. If the comments do not show the need for significant revisions, the footnote will proceed to a recirculation ballot.

Background

FERC Order No. 762, issued April 19, 2012, remanded TPL-002-0b to NERC as vague, unenforceable and not responsive to the previous Commission directives on this matter. The Standards Committee directed the Standards Drafting Team (SDT) to revise footnote ‘b’ in accordance with the directives of Orders No. 693 and 762. The SDT was also charged with revising the corresponding footnote 12 of TPL-001-2 in order to prevent the remand of TPL-001-2.

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Ballot Results	
Ballot Name:	Project 2010-11 Successive Ballot
Ballot Period:	1/2/2013 - 1/11/2013
Ballot Type:	Successive
Total # Votes:	306
Total Ballot Pool:	358
Quorum:	**85.47 % The Quorum has been reached**
Weighted Segment Vote:	65.77 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	102	1	54	0.771	16	0.229	19	13
2 - Segment 2.	10	0.9	4	0.4	5	0.5	0	1
3 - Segment 3.	82	1	38	0.679	18	0.321	15	11
4 - Segment 4.	25	1	8	0.8	2	0.2	8	7
5 - Segment 5.	73	1	30	0.75	10	0.25	21	12
6 - Segment 6.	48	1	21	0.636	12	0.364	10	5
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.5	2	0.2	3	0.3	0	3
9 - Segment 9.	3	0.2	0	0	2	0.2	1	0
10 - Segment 10.	7	0.6	5	0.5	1	0.1	1	0
Totals	**358**	**7.2**	**162**	**4.736**	**69**	**2.464**	**75**	**52**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1		Vijay Sankar		
1	Ameren Services	Kirit Shah	Abstain	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Abstain	

1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Maine Power Company	Joseph Turano Jr.	Negative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Abstain	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	
1	Corporate Risk Solutions, Inc.	Joseph Doetzl	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker	Abstain	
1	Dominion Virginia Power	Michael S Crowley		
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Negative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	FortisBC	Curtis Klashinsky		
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Negative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Negative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JEA	Ted Hobson		
1	KAMO Electric Cooperative	Walter Kenyon		
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Negative	
1	MEAG Power	Danny Dees	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Abstain	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Negative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Negative	
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins	Negative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	

1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Abstain	
1	Seattle City Light	Pawel Krupa	Abstain	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Mississippi Electric Power Association	Rodney A. Wilson		
1	Southern California Edison Company	Steven Mavis	Negative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young	Affirmative	
1	Tennessee Valley Authority	Howell D Scott	Negative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	
2	ISO New England, Inc.	Kathleen Goodman	Negative	
2	Midwest ISO, Inc.	Marie Knox	Negative	
2	New Brunswick System Operator	Alden Briggs	Negative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Negative	
3	Ameren Services	Mark Peters	Abstain	
3	APS	Steven Norris	Negative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Robert Lafferty		
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Homestead	Orestes J Garcia	Affirmative	
3	City of Redding	Bill Hughes	Abstain	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Abstain	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	
3	Consumers Energy	Richard Blumenstock	Abstain	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr		

3	Entergy	Joel T Plessinger	Negative	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey	Negative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Negative	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Abstain	
3	Mississippi Power	Jeff Franklin	Negative	
3	Modesto Irrigation District	Jack W Savage	Negative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Abstain	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Abstain	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Gary Clear		
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Negative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	Snohomish County PUD No. 1	Mark Oens	Abstain	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Negative	
4	American Municipal Power	Kevin Koloini		
4	Arkansas Electric Cooperative Corporation	Ronnie Frizzell		
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Abstain	
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	

4	Consumers Energy	David Frank Ronk	Abstain	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Negative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Abstain	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Jennifer Eckels	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	
5	Consumers Energy Company	David C Greyerbiehl	Abstain	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Electric Power Supply Association	John R Cashin		
5	Energy Services, Inc.	Tracey Stubbs		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Manitoba Hydro	S N Fernando	Negative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Abstain	
5	MidAmerican Energy Co.	Neil D Hammer	Abstain	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		

5	Platte River Power Authority	Roland Thiel	Abstain	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Abstain	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	Southern California Edison Company	Denise Yaffe	Negative	
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Xcel Energy, Inc.	Liam Noailles	Negative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	APS	Randy A. Young	Negative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Abstain	
6	Cleco Power LLC	Robert Hirchak		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Negative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	Modesto Irrigation District	James McFall	Negative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Abstain	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried		
6	PacifiCorp	Kelly Cumiskey	Abstain	
6	Platte River Power Authority	Carol Ballantine	Negative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet		
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	Kenn Backholm	Abstain	
6	South Mississippi Electric Power Association	Joel Rogers		
6	Southern California Edison Company	Lujuanna Medina	Negative	

6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	
8		Edward C Stein		
8		Roger C Zaklukiewicz		
8	JDRJC Associates	Jim Cyrulewski	Negative	
8	Massachusetts Attorney General	Frederick R Plett	Negative	
8	Transmission Strategies, LLC	Bernie M Pasternack	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Abstain	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Negative	
9	New York State Department of Public Service	Thomas G. Dvorsky	Negative	
10	Midwest Reliability Organization	William S Smith	Affirmative	
10	New York State Reliability Council	Alan Adamson	Negative	
10	Northeast Power Coordinating Council	Guy V. Zito	Abstain	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Name (32 Responses)
Organization (32 Responses)
Group Name (17 Responses)
Lead Contact (17 Responses)
Contact Organization (17 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (4 Responses)
Comments (49 Responses)
Question 1 (38 Responses)
Question 1 Comments (45 Responses)
Question 2 (32 Responses)
Question 2 Comments (45 Responses)
Question 3 (30 Responses)
Question 3 Comments (45 Responses)
Question 4 (29 Responses)
Question 4 Comments (45 Responses)

Individual
Frederick R Plett
Massachusetts Attorney General
No
The SDT ignored a lot of feedback concerning the inappropriateness of a 75 MW threshold. IT remains inappropriate and an appropriate level should be decided by local stakeholder processes.
Yes
No
Don't buy the 75 MW or the 25 MW thresholds.
Group
SERC EC Planning Standards Subcommittee
Jim Kelley
PowerSouth Energy Cooperative
Yes
Yes
Yes
Change "does" to "do" in the last sentence of the first paragraph and in the first sentence of the last paragraph in Section III of Attachment 1.
We continue to recommend that up to 25 MW of planned interruption be allowed without triggering the need for a stakeholder process. We believe that this simplification would be less burdensome and would enhance industry acceptance of the revision, while still meeting regulatory guidance. The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Individual
Thad Ness
American Electric Power
Yes
Yes
Yes
No
Individual
Oliver Burke
Entergy Services, Inc. (Transmission)
No

Attachment 1 is overly burdensome and concerns local reliability issues better left to local regulators. A planned or unplanned loss of 25 MW is inconsequential to the reliability of the BES. The footnote could be simplified to exclude attachment 1 as follows: An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to 25 MW and notice must be given to applicable regulatory authorities or governing bodies responsible for retail electric service issues within 30 days of the completion of the assessment which includes the use of footnote 12.
No
Attachment 1 is overly burdensome and unnecessary.
No
Attachment 1 is overly burdensome and unnecessary.
Yes
If Attachment 1 must remain, Entergy would support the SERC PSS suggestion to limit the application of Attachment 1 (the stakeholder process) to only those situations where the non-consequential load at risk is above 25MW.
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
No
Planned interruptions of Firm Demand in response to a Single Contingency (as directed in Footnote b of TPL-002 Table 1, and Footnote 12 of TPL-001-2), is not an acceptable corrective action to mitigate reliability issues on the BES system. The Interconnected System should be designed and operated with enough transfer capacity to be able to withstand, at a minimum, a single contingency event without service interruptions to customer load. Systems must be designed and operated so that the impact of any single contingency can be mitigated by re-dispatching available system resources without the need to implement load shedding.
Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
No
Dropping load generally should not be endorsed, but it is recognized that there are special situations where it cannot be avoided. If a regulator responsible for load is comfortable with greater than 75MW being dropped in a rare situation, there should not be a requirement to build out of the situation. Provided there is no widespread, adverse effect on the reliability of the interconnected BES, the effect of a interruption on customers is under the purview of the applicable regulatory authority that is responsible for local transmission and retail service over the load to be curtailed. NERC must acknowledge that jurisdictional authorities can decide on the parameters for planning events that do not have an impact on the reliability of interconnected BES . There are no limits on non-consequential load loss for Single Contingency P2-2 and P2-3 (HV only), multiple Contingencies P4 and P5 (HV only), and P6 and P7. Footnote 12 allows limited non-consequential load loss for single contingency P1, Multiple Contingency P3. Non-consequential load loss is not allowed for P2-2 and P2-3 (EHV), and P4 and P5 (EHV). Considering the extensive EHV Facilities in the Canadian regions of NPCC, it is not reasonable to accept some non-consequential load loss for single contingency P1 and P2-3, and then deny it for Multiple Contingency categories P4 and P5 which are statistically less frequent than the former. Also, the Multiple Contingency P7 (for which there is no limit on non-consequential load loss) is more frequent than P2-3, P4 and P5. This technical irregularity must be reviewed and addressed. This comment was submitted for the last posting.
Yes
Yes
Individual
David Jendras
Ameren
Yes
Yes
Yes
We find no substantive changes to section III, and still believe that no objection from a regulatory body requires, at a minimum, a tacit approval.

Group
Southwest Power Pool Reliability Standards Development Group
Jonathan Hayes
Southwest Power Pool
Yes
Yes
Yes
Yes
Under section II items 3 and 4 the wording (frequency and duration) seems to implicate that the planners will be determining these events in a probabilistic manor. If the probability of these events is anything other than 0 planners will have to accommodate for those events in their planning assessments regardless of how small the probability is for that event.
Individual
Nazra Gladu
Manitoba Hydro
Yes
Manitoba Hydro agrees that the changes add clarity to the footnote.
No
Any assessment or explanation is only speculation. Is the requirement any different? Item 5 raises an expectation that footnote 12 can only be used on an interim bases – this should be clarified.
Yes
Manitoba Hydro cannot support the Footnote B attachment which imposes a stakeholder process not required in Manitoba.
Individual
David Wang
SDG&E
No
Table 1, footnote b of TPL-002 allows the use of load shedding for the loss of a single element (Category B) under certain circumstances. SDG&E has been against the proposed changes because of the addition of a stakeholder process that allows outside entities to make reliability decisions which we would be held accountable for.
No
No
No
Individual
Bob Easton
WAPA-RMR
No
While Western agrees in general with what is proposed in Footnote b; I do not agree with stipluating 2 requirements in the proposed Footnote b: The 75 MW load threshold; the Attachment 1 Stakeholder process. The 75 MW seems low and NERC should condsider using a 300 MW threshold similar to that used in CIP-002 and EOP-004 requirements.
Yes
No
See response to Question 1.
Yes
I believe that the 75 MW limit is abetrary and could be too low given particular circumstances, like the maginitude of recent load growth in the area, regulatory hurdles in building new transmission, etc. I also believe that the Attachment 1 stakeholder process is not needed, since it is already covered by the FERC Ordered 890 planning process.
Group
Bonneville Power Administration
Jamison Dye
Transmission Reliability Program

Yes
Yes
Yes
No
Group
TVA Transmission Reliability Engineering and Controls
Tim Ponseti, VP
Bulk Transmission Engineering
Yes
Yes
Yes
We recommend that up to 25 MW of planned interruption be allowed without triggering the need for a stakeholder process. We believe that this simplification would be less burdensome and would enhance industry acceptance of the revision, while still meeting regulatory guidance.
Group
Santee Cooper
Terry L. Blackwell
Santee Cooper
No
Santee Cooper will abstain from voting on the revisions to footnote "b" in TPL-002-1c and the corresponding footnote 12 of TPL-001-2. Santee Cooper is concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal power Act and into customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions. However, in the spirit of moving this process forward, Santee Cooper will not vote against the revised footnotes.
Individual
Kenn Backholm
Public Utility District No.1 of Snohomish County
Yes
The Public Utility District No.1 of Snohomish County will abstain from voting on the revisions to footnote "b" in TPL-002-1c and the corresponding footnote 12 of TPL-001-2. The Public Utility District No.1 of Snohomish County is concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal power Act and into customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions (for details on the Public Utility District No.1 of Snohomish County's concerns please see the comments submitted during the initial ballot). However, in the spirit of moving this process forward, the Public Utility District No.1 of Snohomish County will not vote against the revised footnotes.
Group
seattle city light
paul haase
seattle city light
Yes
SCL abstains from voting on the revisions to footnote "b" in TPL-002-1c and the corresponding footnote 12 of TPL-001-2. SCL is

concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal power Act and into customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions (for details onSCL's concerns please see the comments submitted during the initial ballot). However, in the spirit of moving this process forward, SCL will not vote against the revised footnotes.
Individual
Steve Alexxanderson P.E.
Central Lincoln
Yes
Central Lincoln has not paid much attention to this standard, since it is not applicable to this entity's registered functions. However, we are disturbed by the direction the standard is taking. The slides from the recent webinar (http://www.nerc.com/docs/Standards/dt/footnoteb_webinar_20130108_final.pdf) state that "The 75 MW cap will require construction of major Transmission projects." This is in direct conflict with the definition of "reliability standard" as provided in section 215 of the FPA where it states "...the term does not include any requirement to enlarge such facilities or to construct new transmission capacity..." The webinar slide does offer alternatives to construction, but we don't see those providing any reliability benefit. Some of the suggestions apparently only relate to contract language, which cannot possibly relate in any way to "reliable operation" as defined in section 215. Central Lincoln is is concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal power Act and into customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions.
Individual
Milorad Papic
Idaho Power Company
Yes
Yes
Yes
No
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
Agree
We support the comments submitted by Central Lincoln
Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
No
See response to question 4.
No
See response to question 4.
No
See response to question 4.
Yes
ERCOT believes that the revisions to the footnote b attachment are an improvement from the previous version. However, ERCOT does not believe that the SDT provided a technical rationale for disagreeing with the comments that we previously submitted. We fundamentally disagree with the approach of defining a stakeholder process in the attachment to a footnote in a reliability standard. While footnotes and attachments have been used in other standards we believe that this application is not appropriate. ERCOT believes that the footnote should be removed altogether as it does not meet the objectives of FERC Order 693. We also believe that FERC did not mandate that a stakeholder process be used. As stated in the January 8 NERC Industry Webinar, 90% of planning entities have not used the existing footnote b over a planning horizon of 13 years. To incorporate an attachment to a footnote with a complicated and prescriptive stakeholder process to address a few instances seems to be a least common denominator approach to planning which is opposed to FERC's direction. Consistent with the approach of TPL-001-2, ERCOT recommends raising the bar on reliability and removing the footnote from the standard.
Individual
Jim Cyrulewski
JDRJC Associates LLC
Agree

Midwest ISO
Individual
Kathleen Goodman
ISO New England Inc
No
There are jurisdictional issues with the footnote and attachment as written. These will be described in further detail throughout this document. The footnote itself states, “An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events.” A standard should not have requirements described as objectives, this language is extremely subjective.
No
Section II, 2.a, states that studies must address the estimated number and type of customers affected by Non-Consequential Load Shedding. The Transmission Planner in many cases will not be the appropriate entity to address these concerns. The Transmission Owner, Distribution Provider or Load Serving Entities would be the appropriate entities to address customer affects. Explaining effects on the “health, safety, and welfare of the community” is required under the footnote in Section II, 2.b. The same load could be shed directly as the consequence of a fault and no such assessment is required. In addition, Transmission Planners can shed radial load with no assessment of health and welfare. In addition to the practical considerations listed, once again here the standard infringes on Section 215 responsibilities where State authority over the “safety, adequacy and reliability of the electric system in that state” is mandated. This section should be deleted. Section II, requirements 3 and 4 discuss estimating frequency and duration of Non-Consequential Load Loss based on historical performance. The planning process uses deterministic not probabilistic assessments. This section should be deleted.
The footnote states “Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues does not object to the use of Non-Consequential Load Loss under footnote 12 if either…”. Section 215 of the Federal Power Act clearly delineates Federal, State and Local authority. State and Local requirements should not be introduced into a NERC standard. In addition to the jurisdictional issues, proving that the “applicable regulatory authority or governing body” does not object is more difficult than proving that they simply approved the use of non-consequential load loss. The SDT should remove all references to State and Local authority from the standard. Overall, the order of Section III is also notable. During year, two through ten of the overall planning horizon the standard allows for Non-Consequential Load Loss without approval. In the first year of the assessment, approval becomes required for Non-Consequential Load Loss. At this point, it is too late to allow for any other alternative. The Regional Entities with NERC oversight perform periodic audits and require self-certification of the planning process. By virtue of the audit and self-certification process, NERC has the ability to monitor the use of Non-Consequential Load Loss in planning assessments. State and Local approval of practices called for in ERO Standards is inappropriate. In addition to being notable for the year one timing, Section III seems incomplete. In the case where there is objection to Non-Consequential Load Shedding, the process appears to end without resolution.
In summary, this standard as proposed has misplaced jurisdictional authority under Section 215 of the Federal Power Act. The removal of references to State and Local authorities in the standard is required.
Individual
John Collins
Platte River Power Authority
No
Disagree with no change to the 75 MW threshold, but agree with the minor changes that were made since last posting. I request your consideration of a 300 MW threshold similar to that used in CIP-002 and EOP-004. Since there is a directive for some threshold, and in an attempt to reduce the likelihood of over-burdening smaller communities, the 300 MW level would be a more reasonable threshold for the BES.
Yes
No
See answer to Question 1.
No
Individual
Keith Morisette
Tacoma Power
Yes
Yes
Yes
While Tacoma Power appreciates NERC's attempt to address both footnotes with the same drafting team, Tacoma Power is voting negative on the revisions to footnote "b" in TPL-002-1c and the corresponding footnote 12 of TPL-001-2. However, Tacoma Power would vote affirmative if a re-circulation ballot was limited strictly to footnote "b" in TPL-002-1c. TPL-001-2 considered new types

of outages not considered by TPL version 1, such as P2-1. Although TPL-001-2 was approved by the industry, the proposed modifications to footnote 12 in TPL-001-2 are significantly more onerous than footnote 12 in TPL-001-2. Furthermore, since TPL-001-2 is not yet enforceable, some Transmission Planners still do not realize that automatic relay actions are considered Non Consequential Load Loss. In addition, Tacoma Power identified over 100 MW of load in multiple locations that would be shed in accordance with footnote 12 in TPL-001-2. Unfortunately, the structure of the Section 1600 data request did not allow for the submittal of footnote 12 related data. Since it is clear that the potential impact of the footnote 12 revision has not been addressed due to the compressed timeline, Tacoma Power believes that by separating the two standards, NERC can meet the FERC mandated deadline for footnote b while still continuing the drafting process to achieve true industry consensus on footnote 12. Please note that FERC orders 693 and 762 require addressing only footnote "b" by the using the Expedited Standards Development Process. Earlier FERC orders discuss "single contingencies" as type Category B in TPL-002-1; FERC has not addressed Non Consequential Load Shedding for the lower probability "single contingencies" (i.e. P2-1) in TPL-001-2. Approving the revisions to footnote 12 would result in negligible reliability gains at an unreasonable cost for customers on the fringes of the power system, without affording local jurisdictional cost benefit analysis. Tacoma Power is also concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal Power Act. These revisions tread on customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions. For details on Tacoma Power's concerns please see the comments submitted during the initial ballot. However, in the spirit of moving this process forward, Tacoma Power would vote to approve the revisions to solely TPL-002-1c if balloted separately from TPL-001-2. Tacoma Power appreciates the opportunity to provide comments, and thanks you for consideration of our comments.
Individual
Donald Weaver
New Brunswick System Operator
We do not agree with setting a MW limit for non-consequential load loss. The allowable amount should be determined and approved by the jurisdiction of the area(s) whose load is affected. The intent of the TPL standard and this footnote is to ensure that if non-sequential load loss is accounted for or relied up to ensure BES reliability (as assessed in the planning horizon), that such a decision needs to be approved by the appropriate jurisdiction
Group
ACES Standards Collaborators
Ben Engelby
ACES
Yes
(1) We continue to disagree with the 75 MW capacity limit threshold. There is no need for a 75 MW cap because registered entities and local-level policy makers are in the best position to determine an appropriate capacity limit, as stated in the FERC order and in previous feedback. However, if the drafting team decides to move forward with a cap, we suggest using a cap that would reflect all data points from the Section 1600 data request to be under the threshold. The findings to the data request contained a data point at 75.2 MW, which would be over the proposed threshold. We understand this data point, in essence, has been omitted because the use of non-consequential load shedding for the 75.2 MW data point is expected to terminate soon. If the drafting team intends to use the data that represents the actual usage of footnote ‘b’ by planning coordinators, then the team should take into account the highest data point and adjust the threshold to at least 76 MW regardless of the length of time the data point is needed. Again, local decision makers are better equipped to make this type of determination. (2) However, in the spirit of moving forward with this project we will support the changes and thank the drafting team for their efforts.
No
(1) Thank you for making the changes to Section II of Attachment 1. We believe the modification of removing “assessments” and replacing it with “explanation” provides more flexibility regarding how a registered entity can demonstrate the impacts the health, safety and welfare of the community. (2) However, we still believe that the word “alleviate” in bullet 5 requires the same actions as the word “mitigate.” There are instances where no action is required based on a variety of factors. We recommend the following: “Future plans, if necessary, to mitigate/alleviate the need for Non-Consequential Load Loss under footnote 12, unless a determination was made not to mitigate/alleviate, then an explanation why.”
Yes
Yes
(1) In regard to the changes relating to Demand-Side Management, we agree with the wording, “For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of a Contingency, or (2) Interruptible Demand or Demand-Side Management Load.” However, the most recent change has created some confusion by replacing “or” with “and” that potentially and inadvertently may exclude the use of DSM in all locations but on the facilities removed from service. This would render DSM ineffective. Now, the both (1) and (2) must occur in order to not be counted as Firm Demand. We recommend changing the wording back to “or” so each option (1) OR (2) is independently excluded from Firm Demand for footnote b. Connecting the options with the word “and” changes the meaning and requires entities to meet both option (1) and option (2) to be excluded from Firm Demand. Demand directly served by the Elements removed from service as a result of a Contingency should be excluded, as should Interruptible Demand or Demand-Side Management Load regardless of its location. A registered entity does not need to have both for the exclusion. (2) Thank you for the opportunity to comment.
Group
NARUC
Diane Barney

NARUC
No
As stated before, if there is no reliability threat to the bulk system there is no need for the 75 MW limit on the anticipated amount of load to be shed. As long as the regulator responsible for the retail load subject to being shed is notified of the situation, the situation can be appropriately addressed at the local level.
Group
MRO NSRF
WILL SMITH
MIDWEST RELIABILITY ORGANIZATION
Yes
No
The drafting team over specified the Section II stakeholder information process and continues to disregard comments that item 2b be removed from several utilities over several footnote “b” revisions. The goal of Attachment 1 as stated by the drafting team chair was to place “meaningful” parameters around footnote b. The words in 2b on “health, safety, and welfare” are beyond the scope of NERC standards, and are not defined sufficiently in the standard to make the requirement meaningful. The NSRF recommends that if the drafting team doesn’t eliminate 2b, they delete the words “on the health, safety, and welfare of the community” as going beyond NERC jurisdiction, FERC directives, and the SAR. The drafting team response that similar words exist in another standard is not a reason to the ambiguous words in the TPL Attachment 1.
No
The NSRF believes that the standards drafting team did clarify in the webinar that the 25 MW and 75 MW footnote “b” values were separate from interruptible load, and consequential load loss and would not be counted towards the 25 and 75 MW thresholds. However, the NSRF recommends that Attachment 1 also clearly contain an explicit statement “the 25 MW and 75 MW footnote “b” values are separate from consequential load loss, interruptible load, and are not to be counted towards the 25 MW and 75 MW thresholds.”
Yes
Some entities remain concerned over a potential conflict and mismatch of impacts introduced by Section III and the inclusion of non-regulated stakeholders versus NERC regulated entities. There was not a FERC directive to include section III. Section III overreaches the intent of the FERC order and the SAR to meet the FERC directive. The drafting team should show the specific FERC requirement and words in Order 693 that requires non-NERC regulatory reviews. The drafting team technically responded to a request that Section III be removed, but avoided the the fundamental issue. The fact that some existing non-NERC regulatory bodies may already have a consistent practice is not a reason to include non-NERC entities into a NERC framework. This creates a fundamental mismatch between NERC regulated entities that must follow NERC standards and stakeholders that are not compelled by NERC requirements. If Section III is not deleted, it is recommended that wording be added to allow the existing FERC Order 890 stakeholder meeting process be used to meet Attachment 1. Regulators attend these meetings and all stakeholders (including regulators) could be asked for their objections. If there was no response or a “lack of dissent”, this would be documented as meeting Attachment 1 to allow the use of footnote “b” without additional special procedures.
Group
Duke Energy
Greg Rowland
Duke Energy
Yes
Yes
Yes
No
Group
Hydro One Networks Inc.
Sasa Maljukan
Hydro One Networks Inc.
No
In this comment period Hydro One would like to reiterate its initial comments. Hydro One disagrees with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard. Provided there is no widespread, adverse effect on the reliability of the interconnected bulk electric system, the effect on customers of a firm demand interruption is the responsibility of

the applicable regulatory authority or its delegated agencies responsible for local transmission and retail service over the load to be curtailed. If it is decided to proceed with the 75 MW or any other value, we propose replacing the sentence, in the footnote and in attachment one, section III that reads: “In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW.” with “In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss under footnote 12 for a non-US Registered Entity should be determined by the applicable Regulatory Authority or Governmental Authority or its delegated agency in that is responsible for retail electric service issues in that jurisdiction.”
No
As previously stated, we believe that the process presented in Section II is overly prescriptive. If a section that prescribes the information requirements for a stakeholder process is required, then for non-US entities this section should simply require that the process information requirements must be in accordance with the requirements of the applicable Regulatory Authority or Governmental Authority or its delegated agency that is responsible for local transmission and retail service in that jurisdiction.
No
The process presented in Section III is overly prescriptive and duplicates information not necessary for its intended purpose. As stated in Q1, we disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard, and propose alternate language in our response to Q1. If this section is required to address a review of the use of footnote 12 to ensure that there are no wide-spread adverse reliability impacts on the bulk power system, then it should be limited to the information required for that purpose. Provided there is local support for the use of Non-Consequential Load Loss under footnote 12, only information items 6 and 8 from section II are relevant for this assessment—the remainder are not required for this section and should be deleted. Items 1 and 2 complicate this section and are unnecessary. They should be replaced by a phrase such as “for those planning events where the use of footnote 12 is referenced.” We disagree with the need to submit this information to the ERO for a determination of whether there are any Adverse Reliability impacts caused by the use of Non-Consequential Load Loss. This will introduce a new type of review at the ERO that will create unnecessary delays and burden, and is inconsistent with (and not required for) all of the other performance requirements in the TPL standards. Submitting the analysis to the adjacent Planning Coordinators and Transmission Planners, and any functional entity that requests it, as called for in requirement R8 of TPL-001-2 should be sufficient.
Yes
As previously stated in our response to Question #1, Hydro One would like to reiterate our position presented during the initial comment period. We believe that the SDTs response to our initial comments did not correctly address the issues because it did not recognize the Reliability Standards framework that is effective in the Province of Ontario and possibly other Canadian provinces.
Individual
Michiko Sell
Public Utility District No. 2 of Grant County, WA
No
GCPD abstains from voting on the revisions to footnote "b" in TPL-002-1c and the corresponding footnote 12 of TPL-001-2. GCPD is concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal Power Act and into customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions. However, in the spirit of moving this process forward, GCPD did not vote against the revised footnotes.
Individual
Michael Moltane
ITC
MISO
Yes
Yes
Yes
Yes
While ITC is voting yes for this “successive ballot”, we are doing so in the interest of ensuring that TPL 001-2 becomes fully effective as soon as possible. TPL001-2 is a major improvement to previous standards and insuring it becomes fully effective is important to ITC and the industry. However, we have concerns that we would like to be noted. Because footnote B has been highlighted and expanded, there is the possibility of future “unintended consequences”. It is highly likely that interveners or others may attempt to stop or slow down needed corrective action plans, that do not rely on load shedding, by suggesting that planners use this stakeholder process before proposing projects. We suggest both NERC and FERC be prepared to deal with these unintended consequences. We also concur in entirety with the comments MISO is proposing to make for this project. They are consistent with past comments ITC has made and do discuss in some detail the potential “unintended consequences” this detailed footnote may cause.
Group
Western Area Power Administration - Transmission Owner
Lloyd A. Linke
Western Area Power Administration

No
While Western generally agrees with the proposed modification to footnote b, Western does not support the 75 MW threshold and Attachment 1 Stakeholer process. The 75 MW threshold seems to low and if a threshold it needed the drafting team should consider using a 300 MW threshold similar to that used in CIP-002, EOP-004, DOE OE-417 reporting, and NERC event analysis process. The stakeholder process seems to be duplicative, considering there FERC Order 890 planning process.
Yes
No
See answer to Question 1.
Yes
Western believes that the 75 MW limit is arbitrary and could be to low given particular circumstances, like the magnitude of recent load growth in the area, regulatory hurdles in building new transmission, etc. We also believe that the Attachment 1 stakeholder process is not needed, since it is already covered by the FERC Order 890 process.
Individual
Mark Westendorf
MISO
No
MISO does not object to the changes made to the body of the footnote since the previous draft. However, as a general matter, MISO cannot support the current language of Footnote 12. Because the intent of the TPL standards is not to rely on non-consequential firm load shedding after a single contingency event, MISO does not agree that footnote b in NERC TPL-002-1 and/or footnote 12 in TPL-001-2 should be included in these standards. Nonetheless, if these footnotes are included, MISO agrees that there should be some limitation on how much firm load shed is allowed under these footnotes and would not object to the proposed 75 MW level if the footnotes are included.
No
Regarding the use of “explanation” in place of “assessment,” MISO understands that the purpose of this change is to reduce the need for entities to hire expensive consultants and to incur other substantial costs in assessing demographic data and impacts on an affected area. However, as written, this word change potentially places more of a burden on responsible entities. An assessment is an analysis performed using available facts and data while an explanation implies full knowledge. MISO therefore recommends that “assessment” be retained and that a footnote explaining the meaning of that term be added. More generally, however, MISO has concerns regarding the use of a stakeholder process such as the one outlined in Attachment 1 and cannot support the Footnote or Attachment 1 at this time. Please refer to our comments under Question 4 for a more detailed description of these concerns.
No
MISO does not object to the changes made to Section III. However, more generally, MISO has concerns regarding the use of a stakeholder process such as the one outlined in Attachment 1 and cannot support the Footnote or Attachment 1 at this time. Please refer to our comments under Question 4 for a more detailed description of these concerns.
Yes
As previously stated, it is the general intent of the existing TPL-002-1 standard and proposed TPL-001-2 standard to not rely on any shedding of Non-Consequenital Load to meet a single contingency event. Accordingly, MISO submits that footnote b of TPL-002-1 and footnote 12 of TPL-001-2 should be struck. However, in the event that the footnotes in question are not eliminated, the footnote should be narrowly focused only on those situations for which the original footnote was developed, i.e., the interruption of service to radial customers or some local area Network customers connected to or supplied by the Faulted element or by the affected area, where the overall reliability of the interconnected transmission system is not impacted. MISO therefore proposes the following alternate language for footnote b and footnote 12 to ensure it is not misapplied: “An objective of the planning process is to avoid Non-Consequential Load Loss following Contingency events. In limited circumstances, Non-Consequential Load Loss may be needed within the planning horizon to ensure that BES performance requirements are satisfied. However, Non-consequential Load shed cannot be used to avoid cascading outages or to maintain system stability. Non-consequential load shed also cannot be used to avoid a thermal loading or voltage limit violation on an extra high voltage (EHV) facility. When Non-Consequential Load Loss is utilized within the transmission planning horizon to address BES performance requirements, such interruption cannot exceed 75 MW and is limited to the following circumstances: • Non-consequential Load shed is allowed for load served by a radial transmission line to avoid voltage limit violations on the radial transmission line following a single contingency event. • Non-consequential load shed is allowed for load within a local area served by not more than two Transmission Circuits and/or Transformers to avoid a thermal loading issue or voltage issue within the local area, including the Transmission Circuits and/or Transformers directly supplying the local area, for a loss of a single element within the local area, including one of the Transmission Circuits or Transformers directly supplying the local area, so long as there are no thermal loading or voltage violations outside the local area.” MISO believes the language above would ensure the continuing reliability of the Bulk Electric System by limiting load shed and violations that require load shed to radial areas or areas that would be served radially following the single contingency. In addition, MISO has significant concerns regarding use of a stakeholder process to determine if non-conseqeuntial load shedding is appropriate following a single contingency event, as expressed in MISO’s comments on previous drafts of this Project. In particular, MISO has concerns regarding whether such a stakeholder process could be sufficiently open and transparent given the many, competing interests of the responsible entity and affected stakeholders. Without such sufficient openness and transparency, it is likely that stakeholder processes will not result in consistent determinations of the appropriateness of the application of footnote b in NERC TPL-002-1 and/or footnote 12 in TPL-001-2. Stated differently, MISO is concerned that such stakeholder processes will always be subject to the biases of the participating parties, with the sheer number of parties determining the outcome of the process. As an example, should a particular process be dominated by parties that may be responsible for payment of upgrades but that are not impacted by the alternative load shed, those stakeholders impacted by the alternative load loss would be relegated to a minority position, resulting in majority-imposed stakeholder decisions to shed load. On the other hand, if the stakeholder process is limited to only the stakeholders directly impacted by the proposed load shed, to

the extent those stakeholders pay only a small part of the upgrade costs, they will always choose to avoid load shed – even if such decision requires a potentially costly upgrade. Consequently, MISO has concerns that the inclusion of a requirement for a fair and impartial stakeholder process to determine if and when load shed is acceptable to assist in satisfying a single contingency standard is not realistically attainable. MISO therefore recommends that Attachment I be eliminated and that the footnotes either be eliminated or replaced with the modified version above.
Individual
Michael R. Lombardi
Northeast Utilities
No
Northeast Utilities does not support the use of non-consequential demand interruption throughout the planning horizon. Even with the 75 MW limit, NU believes that this language seems to encourage operational workarounds and adds burdens for operators of the system. Lastly, NU believes this use of non-consequential load loss during the planning horizon is not consistent with planning a highly reliable bulk electric system and thus does not support non-consequential load loss for planning purposes.
Individual
Patricia Robertson
BC Hydro
Yes
BC Hydro appreciates the efforts of the SDT in revising standards TPL-002-1c – System Performance Following Loss of a Single BES Element (footnote b) and TPL-001-2a – Transmission System Planning Performance Requirements (footnote 12). BC Hydro votes YES in support of this ballot and wishes to provide the following two comments: 1.At this time BC Hydro has concerns about the level of stakeholder consultation that might be required as a result of the implementation of this standard and will bring this concern to the attention of our regulator if necessary. 2.At this time BC Hydro has concerns about the instances for which regulatory review of non-consequential load loss under footnote 12 is required and will discuss those with our regulator if necessary.
Individual
Teresa Czyz
Georgia Transmission Corp.
Yes
Since this question refers to both footnote b (TPL-002-1c) and footnote 12 (TPL-001-2a), and the changes to the footnotes are not identical, the question should be split into two. Regarding footnote b: An excerpt from footnote b reads “For purposes of this footnote, the following are not counted as Firm Demand (1) Demand directly served by the Elements removed from service as a result of the Contingency …” However, what is being described is in fact Firm Demand (That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions) that is Consequential Load Loss (All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.). Therefore, why not use the terms Consequential Load Loss and Non-Consequential Load Loss? Regarding footnote 12: The replacing the NERC defined “Contingency” event with the undefined “planning” event necessitates a new definition. The intent of the change is unclear.
Yes
Yes
Group
Southern Company
Shih-Min Hsu
Southern Company Services, Inc
Yes
Yes
Yes
Yes
Footnote b contains no technical basis for allowing load dropping. It is completely based on an administrative procedure. This is not

responsive to paragraphs 17 and 32 of the FERC remand order. A technical basis has to be proposed. The "temporarily radial" concept that was proposed in earlier drafts will address this problem. It will give a technical basis for when load dropping would be allowed. If a technical basis is developed like FERC requires, then there is no need for a stakeholder process. The stakeholder process is not a bright line criteria which can be enforced; it will change depending on the make-up of stakeholders and therefore create inconsistencies across the grid. This approach should never be used in a reliability standard. NERC adopted the ANSI standard process as the bench mark in developing its reliability standards. ANSI does not use stakeholder processes. We propose that the stakeholder process be eliminated. Create a technical basis for when load dropping can be utilized. Keep the 75 MW maximum amount of load that can be dropped.
Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
No
Hydro-Québec TransÉnergie (HQT) remains unconvinced that a MW threshold needs to be part of footnote 12. This is not a BES reliability issue but only a matter of service continuity to be addressed by TO/PA/RC with local regulatory authorities.
No
HQT still considers that the non application of footnote 12 to categories P2 (breaker fault), P4 (stuck breaker) and P5 (failure of a non redundant relay) is not correct, when the footnote is applied to other categories such as P3, P6 and P7 (loss of double-circuit lines). The SDT has indicated that the applicability of footnote 12 to categories P2, P4 and P5 is not included in Project 2012-11. However, looking at related Project 2006-02 where footnote 12 was brought up to Table 1, the matter of applicability was not discussed in detail and the SDT did not clearly explain why Non-Consequential Load Loss was not allowed for contingencies less frequent than those for which it is allowed (internal breaker faults or stuck breakers are less probable than double-circuit line faults). Discussion on this matter should not be dismissed.
Individual
Clay Young
SCE&G
No
Comments previously submitted.
No
Comments previously submitted.
No
Comments previously submitted.
No
Individual
Michael Falvo
Independent Electricity System Operator
No
Please note that the Independent Electricity System Operator (IESO), an RTO/ISO registered under Industry Segment 2, has filed an appeal with respect to NERC's response to our similar comments submitted to the previous ballot on this project. We disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard. Provided there is no widespread adverse effect on the reliability of the interconnected bulk power system, the effect on customers of a firm demand interruption is the responsibility of the applicable regulatory authority or its agencies responsible for local transmission and retail service over the load to be curtailed. To recognize NERC's role as the ERO for Ontario and the Memorandum of Understanding between NERC and the Ontario Energy Board, the IESO proposed replacing the sentence, in the footnote and in attachment one, section III that reads: "In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW." with "In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss under footnote 12 for a Registered Entity that is a Canadian Entity (or a Mexican Entity) should be implemented in a manner that is consistent with/or under the direction of the Applicable Governmental Authority or its agency in Canada (or Mexico). Under this language, both the amount of non-consequential load loss, and the process under which that amount was arrived at, including stakeholder consultations, would be determined by the relevant Canadian jurisdiction, in this case Ontario. This change will make the standard acceptable in Ontario's legislative framework, in which NERC standards come into force automatically unless, by order of the Ontario Energy Board, a standard is stayed and remanded back to NERC for further consideration. The responses to the IESO's comments in the previous ballot were inaccurate as to this key feature of the Ontario reliability framework, as addressed in the IESO appeal. An alternate solution to this issue, which would • be consistent with the intent of the responses to the IESO comments on the previous ballot, • respect the Ontario reliability framework, and • resolve the IESO January 9, 2013 appeal; and is appropriate given that these changes are being driven by a U.S. FERC remand order to NERC, would be to make the following highlighted clarifications to footnotes 'b' and 12: With respect to Standard TPL-002-1c — footnote 'b' b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm For purposes of this footnote, the following are not counted as Firm Demand will be interrupted

if itt is: (1) Demand directly served by the Elements removed from service as a result of the Contingency, orand (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, for U.S. registered entities when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for U.S. registered entities. With respect to Standard TPL-001-2a — footnote 12: 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, for U.S. registered entities when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for U.S. registered entities.
No
No. The process presented in Section II is overly prescriptive. If a section that prescribes the information requirements for a stakeholder process is required, then for Canadian entities this section should simply state that any threshold should be established in a manner consistent with other service levels that apply to local transmission and retail service for the load to be curtailed, for the reasons described in Q1.
No
The process presented in Section III is overly prescriptive and requires information not necessary to the intended purpose. As stated in Q1, we disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard, and propose alternate language as stated in Q1 comments and supporting reasons. If this section must deal with a review of the use of footnote 'b'/'12' to ensure that there are no widespread adverse reliability impacts on the bulk power system, then it should be limited to the information required for that purpose. Provided there is local support for the use of Non-Consequential Load Loss under footnote 'b'/'12', only information items 6 and 8 from section II are relevant for this assessment—the remainder are not required for this section and should be deleted. The use of footnote 'b'/'12' should not be limited to the Near-Term Planning Horizon. We propose that the words "in Year One of the Planning Assesssment" be deleted. Items 1 and 2 complicate this section and are unnecessary. They should be replaced by a phrase such as "for those planning events where the use of footnote 'b'/'12' is referenced". We disagree with the need to submit to the ERO for a determination of whether there are any adverse reliability impacts caused by the use of Non-Consequential Load Loss. This will introduce a new type of review at the ERO that will create unnecessary delays and burden, and is inconsistent with and not required for all of the other performance requirements in the TPL standards. Submitting the analysis to the adjacent Planning Coordinators and Transmission Planners, and any functional entity that requests it, as called for in requirement R8 of TPL001-2 should be sufficient.
(1) The IESO reiterate its support for allowing load interruption for a single contingency with sufficient review/oversight and under acceptable conditions, including no widespread adverse impact on the reliability of the interconnected bulk power system. The reliability aspects (BES performance requirements) should be reviewed for acceptability by the adjacent Planning Coordinators and Transmission Planners. However, issues pertaining to economics or externalities which may not be directly reliability-related are always available for review and debate by the stakeholders via the regulatory processes and subject to approval by the regulatory authority of each jurisdiction (including those in Canada and Mexico). (2) Furthermore, we request that Table 1 of TPL-001-3 (previous TPL-001-2 approved by NERC BOT) be corrected for EHV contingencies in P2, P4 and P5 categories to allow the application of footnote 'b'/'12' that is allowed for the P1 events. Events in P2, P4, and P5 can involve more elements and can be more onerous and stressful to the system than the P1 events, and if use of footnote 'b'/'12' is permitted in the less stressful P1 events, it should also be permitted in P2, P4 and P5 events. There continues to be confusion as to this inconsistency, and to how this is to be applied (as discussed at the last webinar). (3) We suggest that NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve it. Accordingly, we believe that the focus of footnote 'b', and footnote 12 should be that interruption of load must not have a widespread, adverse impact on the reliability of the interconnected bulk power system. A continent-wide standard should not concern itself with the reliability of supply or supply continuity for local load, as that is the responsibility of the applicable regulatory authority or its agencies responsible for local transmission and retail service over the load to be curtailed. As mentioned above, NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve it. In this regard, we believe that Attachment 1 is not necessary because it prescribes a process which goes beyond the outcome of the standard and dictates how stakeholdering must be carried out. The individual jurisdiction should establish the process for ensuring compliance with the standard and decide to what extent a stakeholdering process is necessary to establish the acceptable level of load rejection for the area in a manner consistent with local transmission established service levels. (4) The process presented in Section I is overly prescriptive. If a section that prescribes the principles of a stakeholder process is required, then for Canadian entities this section should simply state that any threshold should be established in a manner consistent with other service levels that apply to local transmission and retail service for the load to be curtailed, as described in Q1 and for the reasons stated therein. Corrective action plans can rarely be implemented in a one-year time frame, and in some cases, limited use of Non-consequential Load Loss will be preferable to unaffordable transmission enhancements, therefore we believe that the use of footnote 'b'/'12' should not be limited to the Near-Term Transmission Planning Horizon. We propose that the phrase "the Near-Term Transmission Planning Horizon of" be deleted from the opening paragraph.
Individual
Brett Holland
Kansas City Power & Light
Agree
SPP
Group
Iberdrola USA
John Allen
Rochester Gas & Electric

No
See comment to question 4 below.
No
See comment to question 4 below.
No
See comment to question 4 below.
Yes
The reasons for the “negative” vote are enumerated in our prior comments. In summary: 1. Attachment 1 is cumbersome and inappropriate, and should be stricken entirely. 2. All non-consequential load loss for all single-element contingencies should be temporary, with an action plan to avoid such load loss in the future. 3. All actions following single-element contingencies should be an attempt to restore lost customer service, not interrupt more customers.
Individual
Darryl Curtis
Oncor Electric Delivery Company LLC
Yes
Yes
Yes
No
Individual
Vijayraghavan bangalore
Pacific gas and Electric Comapny
No
We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. Assigning a fixed “not to exceed” number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, “[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events”. It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fix maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving “safe harbor” to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the “not to exceed” amount.
No
Suggest removing item 5, “A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction”. Given that the “applicable regulatory authorities or governing bodies responsible for retail electric service issues” are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?
No
We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the “applicable regulatory authorities or governing bodies responsible for retail electric service issues”.
No
Group
Tri-State G&T
Chris Pink
Chris Pink
No
1. In the last submittal for comments, the following comment was made: It was not clear how transmission projects with long lead times (such as T-lines) would be handled by “Footnote b.” In other words, it is not clear if it is acceptable for a TP to plan for

shedding Firm Demand in the Near Term Planning Horizon without meeting the conditions shown in “Attachment 1” when a mitigating project is planned that cannot be constructed in the Near Term Planning Horizon. The The Standard Drafting Team (SDT) provided the following response: Any instance of proposed load shed for a single Contingency situation in a Planning Assessment must meet the conditions of footnote ‘b.’ No Change made. From the above comments, we believe there is a situation where the Bulk Electric System (BES) reliability is compromised while stakeholder process proceeds.
No
2. As stated previously, NERC Functional Model definitions for Planning Authorities and Transmission Planners do not include the types of activities being proposed in “Attachment 1.” As written, this standard mandates functions on functional entities that are outside those defined by the NERC Functional Model. The SDT acknowledged this by stating that “the NERC Functional Model is a guideline for activities required of cited functional entities.” As such, we still believe that obligations should not be required of entities outside of the NERC Functional Model descriptions.
No
3. Previously, it was commented that it is unclear how section III of “Attachment 1” would be applied to entities that only deliver wholesale electric service and not retail electric service. The response provided by the SDT stated the following: The SDT believes that the wholesale customer will be one of the stakeholders included in the process and any use of footnote must go through the stakeholder process. No change made. If the wholesale customer is one of the stakeholders, the standard needs to add wholesale customers into the language as part of Attachment I. For example, it should read as follows: Coordinator must ensure that the applicable regulatory authorities, wholesale customers, or governing bodies responsible for retail electric service issues does not object to the use of Firm Demand interruptions under footnote ‘b’…
Group
National Grid
Michael Jones
National Grid
Yes
We are accepting the standard as written because our current practices are better then the prescribed maximum limit. However, we believe the appropriate limit should be determined on a case by case basis with the state regulator input. This standard as written, does give us the flexibility to do this.
Individual
Alice Ireland
Xcel Energy
Yes
While we are not satisfied with the responses to our previous comments, we have chosen to not reiterate them here. Instead, we feel that the need to continue with any modification to Footnote b seems moot considering FERC's recent approval of the revised BES definition. Specifically, we believe exclusions E1 and E3, regarding radial systems and local networks, resolves FERC's original directive on ambiguity with footnote b. We recommend the team consider abandoning this project, and request that NERC staff request relief from FERC on the related directives, as they have been overcome by the modified BES definition.
Individual
Tony Kroskey
Brazos Electric Power Cooperative, Inc.
Agree
ACES Power Marketing

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project 2010-11 Revision of TPL-002 footnote 'b'

The Project 2010-11 TPL Table 1 Order Drafting Team thanks all commenters who submitted comments on the proposed standards, TPL-002. The standard was posted for a 30-day public comment period from December 12, 2012 through January 11, 2013. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 49 sets of comments, including comments from approximately 132 different people from approximately 48 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Summary Consideration:

The SDT made one change to the proposed standards to address industry comments. This change was made in the main body of the footnote to address a specific jurisdictional concern for non-US entities.

> **TPL-001-2a and TPL-002-1c (main body of the footnote) -** In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

In order to avoid confusion, a duplicative statement on the applicability of the 75 MW constraint was deleted from Section III.

The SDT also corrected the grammar in Section III, changing 'does' to 'do' in the applicable sentences, as follows:

> **Section III –** "… the applicable regulatory authorities or governing bodies responsible for retail electric service issues do~~es~~ not object …"

In addition, in the course of researching industry comments, a typo was discovered and corrected as follows:

> **TPL-002-1c: footnote 'b' –** "…For purposes of this footnote, the following are not counted as Firm Demand~~t~~: (1) …"

No other changes were made.

While the revision for non-US registered entities qualifies as a significant change to the standards, the Standards Committee has decided that since the indicated change was simply for a jurisdictional issue, and did not change the technical content or intent of the standard, that this project can be moved forward to the recirculation ballot stage.

Unresolved minority issues:

Some respondents continue to raise jurisdictional concerns with the proposed standards. The general line of thought in those comments is that NERC is imposing itself into the local planning process in violation of existing statutes. The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. In Order 693, FERC clearly stated that it has jurisdiction over matters that involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote ‘b’ solution acknowledges these facts and the SDT believes it is an appropriate response to FERC directives on this matter.

Many commenters questioned the use of a stakeholder process at all. Those commenters expressed the opinion that the FERC Order did not mandate the use of the stakeholder process. The SDT used the Board of Trustees approved standard as a starting point for this draft. FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach, in order to address these concerns.

A few commenters indicated disagreement with the 75 MW limit the proposed standards place on the amount of Non-Consequential Load that can be planned to be shed for a single contingency, with some commenters indicating that the limit should be higher than the proposed limit while others indicated that planning to shed load was inconsistent with planning for a reliable bulk power system.

Finally, some commenters continue to question facets of the proposed TPL-001-2a standard previously approved by the industry and the NERC Board of Trustees. These commenters are questioning the application (or non-application) of footnote 12 for various planning events. . The SAR for this project took the approved TPL-001-2 as the starting point for the specific discussion of footnote ‘b’/12 and does not allow for review of previously approved applications of the footnote, which were developed and reached ballot pool consensus and Board approval in a previous effort.

All comments submitted may be reviewed in their original format on the standard’s project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Jim Kelley	SERC EC Planning Standards Subcommittee	X				X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Company	SERC	1
2.	Charles Long	Entergy	SERC	1
3.	Edin Habibovic	Entergy	SERC	1
4.	James Manning	NC Electric Membership Corporation	SERC	1
5.	Philip Kleckley	SC Electric & Gas	SERC	1
6.	Shih-Min Hsu	Southern Company Service	SERC	1
7.	Darrin Church	TVA	SERC	1
8.	Bob Jones	Southern Company Service	SERC	1
9.	Pat Huntley	SERC Reliability Corporation	SERC	10

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Wayne Sipperly	New York Power Authority	NPCC	5
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Donald Weaver	New Brunswick System Operator	NPCC	2
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Christina Loncz	PSEG Power LLC	NPCC	5
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Group	X	X	X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	Robert Rhodes	Southwest Power Pool	SPP	NA
3.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
4.	Don Taylor	Westar Energy	SPP	1, 3, 5, 6
5.	Stephen McGie	City of Coffeyville	SPP	NA
6.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5.	Group	Terry L. Blackwell	Santee Cooper	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Vicky Budreau	Santee Cooper	SERC	1
2.	Jim Peterson	Santee Cooper	SERC	1
3.	Chris Jimenez	Santee Cooper	SERC	1
4.	Chris Wagner	Santee Cooper		1
5.	Cindy Corson	Santee Cooper		1
6.	Mike Coker	Santee Cooper	SERC	1
7.	Rene' Free	Santee Cooper	SERC	1
8.	Tom Abrams	Santee Cooper	SERC	1
9.	Rick Thornton	Santee Cooper	SERC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	paul haase	seattle city light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	pawel krupa	seattle city light	WECC	1
2.	dana wheelock	seattle city light	WECC	3
3.	hao li	seattle city light	WECC	4
4.	mike haynes	seattle city light	WECC	5
5.	dennis sismaet	seattle city light	WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Ben Engelby	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Shaver	Arizona Electric Power Cooperative Inc./Southwest Transmission Cooperative Inc.	WECC	1, 4, 5
2.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
3.	Amber Anderson	East Kentucky Power Cooperative	SERC	1, 3, 5
4.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
5.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
6.	Scott Brame	North Carolina Electric Membership Corporation	RFC	1, 3, 4, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

Additional Member	Additional Organization	Region	Segment Selection
2. TOM BREENE	WPS	MRO	3, 4, 5, 6
3. JODI JENSON	WAPA	MRO	1, 6
4. KEN GOLDSMITH	ALTW	MRO	4
5. DAVE RUDPOLPH	BEPC	MRO	1, 3, 5, 6
6. ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
7. JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
8. SCOTT NICKELS	RPU	MRO	4
9. TERRY HARBOUR	MEC	MRO	1, 3, 5, 6
10. MARIE KNOX	MISO	MRO	2
11. LEE KITTELSON	OTP	MRO	1, 3, 5
12. SCOTT BOS	MPW	MRO	1, 3, 5, 6
13. TONY EDDLEMAN	NPPD	MRO	1, 3, 5
14. MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
15. DAN INMAN	MPC	MRO	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
9.	Group	Greg Rowland	Duke Energy	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Doug Hils	Duke Energy	RFC	1
2. Lee Schuster	Duke Energy	FRCC	3
3. Dale Goodwine	Duke Energy	SERC	5
4. Greg Cecil	Duke Energy	RFC	6

				1	2	3	4	5	6	7	8	9	10
10.	Group	Sasa Maljukan	Hydro One Networks Inc.	X									

Additional Member	Additional Organization	Region	Segment Selection
1. David Kiguel	Hydro One Networks Inc.	NPCC	1
2. Hamid Hamadanizadeh	Hydro One Networks Inc.	NPCC	1

				1	2	3	4	5	6	7	8	9	10
11.	Group	John Allen	Iberdrola USA	X									

Additional Member	Additional Organization	Region	Segment Selection
1. Joseph Turano	Central Maine Power	NPCC	1
2. Raymond Kinney	New York State Electric & Gas	NPCC	1
3. David Conroy	Central Maine Power	NPCC	1

				1	2	3	4	5	6	7	8	9	10
12.	Group	Michael Jones	National Grid	X		X							

Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Michael Schiavone	Niagara Mohawk (A National Grid Company)	NPCC 3										
13.	Individual	Chris Pink	Tri-State G&T	X		X		X					
14.	Individual	Tim Ponseti, VP	TVA Transmission Reliability Engineering and Controls	X								X	
15.	Individual	Diane Barney	NARUC									X	
16.	Individual	Lloyd A. Linke	Western Area Power Administration - Transmission Owner	X									
17.	Individual	Shih-Min Hsu	Southern Company	X		X		X	X				
18.	Individual	Frederick R Plett	Massachusetts Attorney General								X		
19.	Individual	Thad Ness	American Electric Power	X		X		X	X				
20.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X									
21.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
22.	Individual	David Jendras	Ameren	X		X		X	X				
23.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
24.	Individual	David Wang	SDG&E	X									
25.	Individual	Bob Easton	WAPA-RMR	X								X	
26.	Individual	Kenn Backholm	Public Utility District No.1 of Snohomish County	X		X	X	X	X			X	
27.	Individual	Steve Alexxanderson P.E.	Central Lincoln			X	X					X	
28.	Individual	Milorad Papic	Idaho Power Company	X									
29.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						
30.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
31.	Individual	Jim Cyrulewski	JDRJC Associates LLC								X		
32.	Individual	Kathleen Goodman	ISO New England Inc		X								
33.	Individual	John Collins	Platte River Power Authority	X									
34.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
35.	Individual	Donald Weaver	New Brunswick System Operator		X								
36.	Individual	Michiko Sell	Public Utility District No. 2 of Grant County, WA	X		X	X	X	X				
37.	Individual	Michael Moltane	ITC	X									
38.	Individual	Mark Westendorf	MISO		X								
39.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
40.	Individual	Patricia Robertson	BC Hydro	X	X	X		X					
41.	Individual	Teresa Czyz	Georgia Transmission Corp.	X									
42.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
43.	Individual	Clay Young	SCE&G	X		X		X	X				
44.	Individual	Michael Falvo	Independent Electricity System Operator		X								
45.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
46.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
47.	Individual	Vijayraghavan bangalore	Pacific gas and Electric Comapny	X									
48.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
49.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The SDT thanks you for following the instructions and lessening the SDT workload. Your support for comments submitted by another entity will be noted accordingly.

Organization	Supporting Comments of “Entity Name”
Flathead Electric Cooperative, Inc.	We support the comments submitted by Central Lincoln
JDRJC Associates LLC	Midwest ISO
Kansas City Power & Light	SPP
Brazos Electric Power Cooperative, Inc.	ACES Power Marketing
ITC	MISO

1. **Do you agree with changes made to the body of the footnote? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comment**

Summary Consideration: In general, the SDT has responded to the individual comments and there are no technical changes proposed to the standards as a result of comments. However, the SDT has responded to a request from Canadian entities to make a change to the main body of the footnotes to address specific jurisdictional concerns for non-US registered entities.

> **TPL-001-2a and TPL-002-1c** (main body of the footnote) **-** In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

While the revision for non-US registered entities qualifies as a significant change to the standards, the Standards Committee has decided that since the indicated change was simply for a jurisdictional issue, and did not change the technical content or intent of the standard, that this project can be moved forward to the recirculation ballot stage.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	Dropping load generally should not be endorsed, but it is recognized that there are special situations where it cannot be avoided. If a regulator responsible for load is comfortable with greater than 75MW being dropped in a rare situation, there should not be a requirement to build out of the situation. Provided there is no widespread, adverse effect on the reliability of the interconnected BES, the effect of a interruption on customers is under the purview of the applicable regulatory authority that is responsible for local transmission and retail service over the load to be curtailed. NERC must acknowledge that jurisdictional authorities can decide on the parameters for planning events that do not have an impact on the reliability of interconnected BES . There are no limits on non-consequential load loss for Single Contingency

Organization	Yes or No	Question 1 Comment
		P2-2 and P2-3 (HV only), multiple Contingencies P4 and P5 (HV only), and P6 and P7. Footnote 12 allows limited non-consequential load loss for single contingency P1, Multiple Contingency P3. Non-consequential load loss is not allowed for P2-2 and P2-3 (EHV), and P4 and P5 (EHV). Considering the extensive EHV Facilities in the Canadian regions of NPCC, it is not reasonable to accept some non-consequential load loss for single contingency P1 and P2-3, and then deny it for Multiple Contingency categories P4 and P5 which are statistically less frequent than the former. Also, the Multiple Contingency P7 (for which there is no limit on non-consequential load loss) is more frequent than P2-3, P4 and P5. This technical irregularity must be reviewed and addressed. This comment was submitted for the last posting.
Response: The SDT has previously pointed out that building is not the sole source of remedy for the situation. Examples of other allowable actions were specifically provided in the January 8, 2013 webinar (http://www.nerc.com/docs/Standards/dt/footnoteb_webinar_20130108_final.pdf). No change made. The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. And when such decisions do not involve any aspect of BES operation or reliability, such situations would not come under the purview of footnote 'b' as standards only apply to the BES unless stated otherwise. However, in Order 693, FERC clearly stated that it has jurisdiction over matters that involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote 'b' solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. No change made. Table 1 in the proposed TPL-001-2 was previously approved by industry through the standards development process. As shown by this approval, the SDT and the industry disagree that there is a technical irregularity in Table 1. The Board of Trustees has also previously approved this proposed standard. Discussions on the applicability of footnote 12 in that standard were held during Project 2006-02 and are not part of this proceeding. No change made.		
Public Utility District No. 2 of Grant County, WA	No	GCPD abstains from voting on the revisions to footnote "b" in TPL-002-1c and the corresponding footnote 12 of TPL-001-2. GCPD is concerned that the revised language oversteps the bounds of the "reliability standard"

Organization	Yes or No	Question 1 Comment
		definition under Section 215 of the Federal Power Act and into customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions. However, in the spirit of moving this process forward, GCPD did not vote against the revised footnotes.
Santee Cooper	No	Santee Cooper will abstain from voting on the revisions to footnote "b" in TPL-002-1c and the corresponding footnote 12 of TPL-001-2. Santee Cooper is concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal power Act and into customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions. However, in the spirit of moving this process forward, Santee Cooper will not vote against the revised footnotes.
Response: The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. And when such decisions do not involve any aspect of BES operation or reliability, such situations would not come under the purview of footnote 'b' as standards only apply to the BES unless stated otherwise. However, in Order 693, FERC clearly stated that it has jurisdiction over matters that involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote 'b' solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. No change made.		
Hydro One Networks Inc.	No	In this comment period Hydro One would like to reiterate its initial comments. Hydro One disagrees with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard. Provided there is no widespread, adverse effect on the reliability of the interconnected bulk electric system, the effect on customers of a firm demand interruption is the responsibility of the applicable regulatory authority or its delegated agencies responsible for local transmission and retail

Organization	Yes or No	Question 1 Comment
		service over the load to be curtailed. If it is decided to proceed with the 75 MW or any other value, we propose replacing the sentence, in the footnote and in attachment one, section III that reads:"In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW." with "In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss under footnote 12 for a non-US Registered Entity should be determined by the applicable Regulatory Authority or Governmental Authority or its delegated agency in that is responsible for retail electric service issues in that jurisdiction."
Response: The SDT has made a change to the main body of the footnotes to address the concerns of non-US registered entities. **TPL-001-2a and TPL-002-1c** (main body of the footnote) **-** In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.		
NARUC	No	As stated before, if there is no reliability threat to the bulk system there is no need for the 75 MW limit on the anticipated amount of load to be shed. As long as the regulator responsible for the retail load subject to being shed is notified of the situation, the situation can be appropriately addressed at the local level.
Response: The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. In Order 693, FERC clearly stated that it has jurisdiction over matters that do involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote 'b' solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. No change made.		

Organization	Yes or No	Question 1 Comment
SCE&G	No	Comments previously submitted.
Response: Thank you for following the guidelines. Please see previous responses to this comment posted for the comment period ending November 19, 2012.		
Independent Electricity System Operator	No	Please note that the Independent Electricity System Operator (IESO), an RTO/ISO registered under Industry Segment 2, has filed an appeal with respect to NERC's response to our similar comments submitted to the previous ballot on this project. We disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard. Provided there is no widespread adverse effect on the reliability of the interconnected bulk power system, the effect on customers of a firm demand interruption is the responsibility of the applicable regulatory authority or its agencies responsible for local transmission and retail service over the load to be curtailed. To recognize NERC's role as the ERO for Ontario and the Memorandum of Understanding between NERC and the Ontario Energy Board, the IESO proposed replacing the sentence, in the footnote and in attachment one, section III that reads:"In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW." with "In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss under footnote 12 for a Registered Entity that is a Canadian Entity (or a Mexican Entity) should be implemented in a manner that is consistent with/or under the direction of the Applicable Governmental Authority or its agency in Canada (or Mexico).Under this language, both the amount of non-consequential load loss, and the process under which that amount was arrived at, including stakeholder consultations, would be determined by the relevant Canadian jurisdiction, in this case Ontario.

Organization	Yes or No	Question 1 Comment
		This change will make the standard acceptable in Ontario's legislative framework, in which NERC standards come into force automatically unless, by order of the Ontario Energy Board, a standard is stayed and remanded back to NERC for further consideration. The responses to the IESO's comments in the previous ballot were inaccurate as to this key feature of the Ontario reliability framework, as addressed in the IESO appeal. An alternate solution to this issue, which would o be consistent with the intent of the responses to the IESO comments on the previous ballot, o respect the Ontario reliability framework, and o resolve the IESO January 9, 2013 appeal; and is appropriate given that these changes are being driven by a U.S. FERC remand order to NERC, would be to make the following highlighted clarifications to footnotes 'b' and 12:With respect to Standard TPL-002-1c - footnote 'b' b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm For purposes of this footnote, the following are not counted as Firm Demand will be interrupted if itt is: (1) Demand directly served by the Elements removed from service as a result of the Contingency, or and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, for U.S. registered entities when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to

Organization	Yes or No	Question 1 Comment
		circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for U.S. registered entities. With respect to Standard TPL-001-2a - footnote 12:12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, for U.S. registered entities when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for U.S. registered entities.
Response: The SDT has made a change to the main body of the footnotes to address the concerns of non-US registered entities. **TPL-001-2a and TPL-002-1c** (main body of the footnote) **-** In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.		
Iberdrola USA	No	See comment to question 4 below.
Electric Reliability Council of Texas, Inc.	No	See response to question 4.
Response: See response to Q4.		
Tri-State G&T	No	1. In the last submittal for comments, the following comment was made: It was not clear how transmission projects with long lead times (such as T-lines) would be handled by "Footnote b." In other words, it is not clear

Organization	Yes or No	Question 1 Comment
		if it is acceptable for a TP to plan for shedding Firm Demand in the Near Term Planning Horizon without meeting the conditions shown in “Attachment 1” when a mitigating project is planned that cannot be constructed in the Near Term Planning Horizon. The Standard Drafting Team (SDT) provided the following response: Any instance of proposed load shed for a single Contingency situation in a Planning Assessment must meet the conditions of footnote ‘b.’ No Change made. From the above comments, we believe there is a situation where the Bulk Electric System (BES) reliability is compromised while stakeholder process proceeds.
Response: This standard ensures these items are addressed in planning prior to them becoming an issue in operations so the SDT believes that BES reliability is not being compromised. No change made.		
Western Area Power Administration - Transmission Owner	No	While Western generally agrees with the proposed modification to footnote b, Western does not support the 75 MW threshold and Attachment 1 Stakeholer process. The 75 MW threshold seems to low and if a threshold it needed the drafting team should consider using a 300 MW threshold similar to that used in CIP-002, EOP-004, DOE OE-417 reporting, and NERC event analysis process. The stakeholder process seems to be duplicative, considering there FERC Order 890 planning process.
WAPA-RMR	No	While Western agrees in general with what is proposed in Footnote b; I do not agree with stipluating 2 requirements in the proposed Footnote b: The 75 MW load threshold; the Attachment 1 Stakeholder process. The 75 MW seems low and NERC should condsider using a 300 MW threshold similar to that used in CIP-002 and EOP-004 requirements.
Response: The SDT established the limit based on the results of the Section 1600 data request which clearly pointed to 75 MW as a reasonable limit. While the SDT considered a higher limit value, the data collected does not justify such an action. The SDT used the		

Organization	Yes or No	Question 1 Comment
Board of Trustees approved standard as a starting point for this draft. FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. The use of footnotes and attachments is an acceptable mechanism for use in Reliability Standards and both mechanisms have been used before. No change made. The phrase in Section I: "The responsible entity can utilize an existing process or develop a new process" was designed to allow an entity to use an existing process as long as it meets the requirements shown in Attachment 1. No change made.		
Massachusetts Attorney General	No	The SDT ignored a lot of feedback concerning the inappropriateness of a 75 MW threshold. IT remains inappropriate and an appropriate level should be decided by local stakeholder processes.
Response: The SDT established the limit based on the results of the Section 1600 data request which clearly pointed to a 75 MW limit. While the SDT considered a higher limit value, the data collected does not justify such an action. The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. In Order 693, FERC clearly stated that it has jurisdiction over matters that involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote 'b' solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. No change made.		
Entergy Services, Inc. (Transmission)	No	Attachment 1 is overly burdensome and concerns local reliability issues better left to local regulators. A planned or unplanned loss of 25 MW is inconsequential to the reliability of the BES. The footnote could be simplified to exclude attachment 1 as follows: An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES

Organization	Yes or No	Question 1 Comment
		performance requirements, such interruption is limited to 25 MW and notice must be given to applicable regulatory authorities or governing bodies responsible for retail electric service issues within 30 days of the completion of the assessment which includes the use of footnote 12.
Response: The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. In Order 693, FERC clearly stated that it has jurisdiction over matters that involve BES operations and reliability and the proposed footnote ‘b’ solution acknowledges that fact and is an appropriate response to subsequent FERC directives on this matter. No change made. The SDT disagrees that Attachment 1 is overly burdensome as it simply addresses items that would be part of a Transmission Planner’s normal workload. No change made. As approved by the Board of Trustees, all utilizations of footnote ‘b’ required the use of the stakeholder process. The current proposal does not, and should not, deviate from this premise. The Remand Order stated that quantitative criteria needed to be supplied for the stakeholder process and the current proposal provides that criteria. No change made.		
Consolidated Edison Co. of NY, Inc.	No	Planned interruptions of Firm Demand in response to a Single Contingency (as directed in Footnote b of TPL-002 Table 1, and Footnote 12 of TPL-001-2), is not an acceptable corrective action to mitigate reliability issues on the BES system. The Interconnected System should be designed and operated with enough transfer capacity to be able to withstand, at a minimum, a single contingency event without service interruptions to customer load. Systems must be designed and operated so that the impact of any single contingency can be mitigated by re-dispatching available system resources without the need to implement load shedding.
Response: The SDT believes that special circumstances may exist where such actions as described in footnote ‘b’ are appropriate to meet the performance requirements of TPL. The footnote allows for such circumstances to exist in a controlled and prescribed environment where such usages can be discussed and resolved in an open and transparent process. No change made.		

Organization	Yes or No	Question 1 Comment
SDG&E	No	Table 1, footnote b of TPL-002 allows the use of load shedding for the loss of a single element (Category B) under certain circumstances. SDG&E has been against the proposed changes because of the addition of a stakeholder process that allows outside entities to make reliability decisions which we would be held accountable for.
Response: The SDT believes that the described process allows for open and transparent discussion of the potential use of footnote 'b' in the planning environment and disagrees that anything in the proposed footnote provides outside entities with the ability to make reliability decisions. No change made.		
Platte River Power Authority	No	Disagree with no change to the 75 MW threshold, but agree with the minor changes that were made since last posting. I request your consideration of a 300 MW threshold similar to that used in CIP-002 and EOP-004. Since there is a directive for some threshold, and in an attempt to reduce the likelihood of over-burdening smaller communities, the 300 MW level would be a more reasonable threshold for the BES.
Response: The SDT established the limit based on the results of the Section 1600 data request which clearly pointed to a 75 MW limit. While the SDT considered a higher limit value, the data collected does not justify such an action. No change made.		
ISO New England Inc	No	There are jurisdictional issues with the footnote and attachment as written. These will be described in further detail throughout this document. The footnote itself states, "An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events." A standard should not have requirements described as objectives, this language is extremely subjective.
Response: The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. And when such decisions do not involve any aspect of BES operation or reliability, such situations would not come under the purview		

Organization	Yes or No	Question 1 Comment
of footnote ‘b’ as standards only apply to the BES unless stated otherwise. However, in Order 693, FERC clearly stated that it has jurisdiction over matters that do involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote ‘b’ solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. No change made. The SDT does not believe that the stated objective serves as a requirement. No change made.		
MISO ITC JDRJC Associates LLC	No	MISO does not object to the changes made to the body of the footnote since the previous draft. However, as a general matter, MISO cannot support the current language of Footnote 12. Because the intent of the TPL standards is not to rely on non-consequential firm load shedding after a single contingency event, MISO does not agree that footnote b in NERC TPL-002-1 and/or footnote 12 in TPL-001-2 should be included in these standards. Nonetheless, if these footnotes are included, MISO agrees that there should be some limitation on how much firm load shed is allowed under these footnotes and would not object to the proposed 75 MW level if the footnotes are included.
Response: Thank you for your support. The SDT believes that special circumstances may exist where such actions as described in footnote ‘b’ are appropriate to meet the performance requirements of TPL. The footnote allows for such circumstances to exist in a controlled and prescribed environment where such usages can be discussed and resolved in an open and transparent process. No change made.		
Northeast Utilities	No	Northeast Utilities does not support the use of non-consequential demand interruption throughout the planning horizon. Even with the 75 MW limit, NU believes that this language seems to encourage operational workarounds and adds burdens for operators of the system. Lastly, NU believes this use of non-consequential load loss during the planning horizon is not consistent with planning a highly reliable bulk

Organization	Yes or No	Question 1 Comment
		electric system and thus does not support non-consequential load loss for planning purposes.
Response: The SDT believes that special circumstances may exist where such actions as described in footnote 'b' are appropriate to meet the performance requirements of TPL. The footnote allows for such circumstances to exist in a controlled and prescribed environment where such usages can be discussed and resolved in an open and transparent process. No change made.		
Hydro-Quebec TransEnergie	No	Hydro-QuÃ©bec TransÃ‰nergie (HQT) remains unconvinced that a MW threshold needs to be part of footnote 12. This is not a BES reliability issue but only a matter of service continuity to be addressed by TO/PA/RC with local regulatory authorities.
Response: The SDT Believes that the FERC Orders made it clear that the concept of dropping Non-Consequential Load for a N-1 Contingency must include MW thresholds. The SDT has made a change to the main body of the footnotes to address the concerns of non-US registered entities. **TPL-001-2a and TPL-002-1c** (main body of the footnote) **-** In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.		
Pacific gas and Electric Comapny	No	We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. Assigning a fixed "not to exceed" number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, "[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events". It is clear that the spirit

Organization	Yes or No	Question 1 Comment
		of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fix maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving "safe harbor" to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the "not to exceed" amount.
Response: The development of a standard that allowed for the use of footnote 'b' without quantifiable criteria was not acceptable to FERC as shown in the Remand Order. There is no 'safe harbor' up to the identified limit since it will be discussed in an open and transparent stakeholder process that includes applicable regulators. No change made.		
ACES Standards Collaborators Brazos	Yes	(1) We continue to disagree with the 75 MW capacity limit threshold. There is no need for a 75 MW cap because registered entities and local-level policy makers are in the best position to determine an appropriate capacity limit, as stated in the FERC order and in previous feedback. However, if the drafting team decides to move forward with a cap, we suggest using a cap that would reflect all data points from the Section 1600 data request to be under the threshold. The findings to the data request contained a data point at 75.2 MW, which would be over the proposed threshold. We understand this data point, in essence, has been omitted because the use of non-consequential load shedding for the 75.2 MW data point is expected to terminate soon. If the drafting team intends to use the data that represents the actual usage of footnote 'b' by planning coordinators, then the team should take into account the highest data point and adjust the threshold to at least 76 MW regardless of the length of time the data point is needed. Again,

Organization	Yes or No	Question 1 Comment
		local decision makers are better equipped to make this type of determination. (2) However, in the spirit of moving forward with this project we will support the changes and thank the drafting team for their efforts.
Response: The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. In Order 693, FERC clearly stated that it has jurisdiction over matters that do involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote 'b' solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. The SDT established the limit based on the results of the Section 1600 data request which clearly pointed to a 75 MW limit. While the SDT considered a higher limit value, the data collected does not justify such an action. No change made. Thank you for your support.		
Georgia Transmission Corp.	Yes	Since this question refers to both footnote b (TPL-002-1c) and footnote 12 (TPL-001-2a), and the changes to the footnotes are not identical, the question should be split into two. Regarding footnote b: An excerpt from footnote b reads "For purposes of this footnote, the following are not counted as Firm Demand (1) Demand directly served by the Elements removed from service as a result of the Contingency ..." However, what is being described is in fact Firm Demand (That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions) that is Consequential Load Loss (All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.). Therefore, why not use the terms Consequential Load Loss and Non-Consequential Load Loss? Regarding footnote 12: The replacing the NERC defined "Contingency" event with the undefined "planning" event necessitates a new definition.

Organization	Yes or No	Question 1 Comment
		The intent of the change is unclear.
Response: The issue is one of timing. The indicated terms are part of the proposed TPL-001-2 solution and were not in existence when TPL-002-1 was developed. Since the SDT cannot control how FERC will respond to the proposed solutions to this project, it is possible that TPL-002-1 could be approved prior to TPL-001-2. This would create considerable confusion as to the use of these terms. Therefore, the SDT wrote the proposed solutions separately. No change made. The wording change now makes the terminology consistent in both Table 1 and the text. No change made.		
Manitoba Hydro	Yes	Manitoba Hydro agrees that the changes add clarity to the footnote.
SERC EC Planning Standards Subcommittee	Yes	
Southwest Power Pool Reliability Standards Development Group Kansas City Power & Light	Yes	
Bonneville Power Administration	Yes	
MRO NSRF	Yes	
Duke Energy	Yes	
TVA Transmission Reliability Engineering and Controls	Yes	
Southern Company	Yes	
American Electric Power	Yes	
Ameren	Yes	

Organization	Yes or No	Question 1 Comment
Idaho Power Company	Yes	
Tacoma Power	Yes	
ITC	Yes	
Oncor Electric Delivery Company LLC	Yes	
Response: Thank you for your support.		

2. **Do you agree with the changes contained in Section II of Attachment 1? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments**

Summary Consideration: The SDT has responded to the individual comments and there are no changes proposed to the standards as a result of comments.

Organization	Yes or No	Question 2 Comment
ACES Standards Collaborators Brazos	No	(1) Thank you for making the changes to Section II of Attachment 1. We believe the modification of removing "assessments" and replacing it with "explanation" provides more flexibility regarding how a registered entity can demonstrate the impacts the health, safety and welfare of the community. (2) However, we still believe that the word "alleviate" in bullet 5 requires the same actions as the word "mitigate." There are instances where no action is required based on a variety of factors. We recommend the following: "Future plans, if necessary, to mitigate/alleviate the need for Non-Consequential Load Loss under footnote 12, unless a determination was made not to mitigate/alleviate, then an explanation why."
Response: Thank you for your support. This is an information section and not a requirement for a more permanent solution. Therefore, if there is no plan to alleviate then an entity simply documents that fact. No change made.		
MRO NSRF	No	The drafting team over specified the Section II stakeholder information process and continues to disregard comments that item 2b be removed from several utilities over several footnote "b" revisions. The goal of Attachment 1 as stated by the drafting team chair was to place "meaningful" parameters around footnote b. The words in 2b on "health, safety, and welfare" are beyond the scope of NERC standards, and are not defined sufficiently in the standard to make the

Organization	Yes or No	Question 2 Comment
		requirement meaningful. The NSRF recommends that if the drafting team doesn't eliminate 2b, they delete the words "on the health, safety, and welfare of the community" as going beyond NERC jurisdiction, FERC directives, and the SAR. The drafting team response that similar words exist in another standard is not a reason to the ambiguous words in the TPL Attachment 1.
Response: The SDT did not justify the retention of the subject phrase simply because similar words exist in another standard but because the burden and intent of the phrase in footnote 'b' is consistent with what entities are required to do in that other standard (the phrase is included in EOP-001 as part of a description of Load curtailment in Attachment 1 of EOP-001, which describes elements for consideration in developing emergency plans). The SDT believes that the changes made in this posting clarify the intent of this requirement. No change made.		
Hydro One Networks Inc.	No	As previously stated, we believe that the process presented in Section II is overly prescriptive. If a section that prescribes the information requirements for a stakeholder process is required, then for non-US entities this section should simply require that the process information requirements must be in accordance with the requirements of the applicable Regulatory Authority or Governmental Authority or its delegated agency that is responsible for local transmission and retail service in that jurisdiction.
Independent Electricity System Operator	No	No. The process presented in Section II is overly prescriptive. If a section that prescribes the information requirements for a stakeholder process is required, then for Canadian entities this section should simply state that any threshold should be established in a manner consistent with other service levels that apply to local transmission and retail service for the load to be curtailed, for the reasons described in Q1.
Response: The SDT has made a change to the main body of the footnotes to address the concerns of non-US registered entities. **TPL-001-2a and TPL-002-1c** (main body of the footnote) **-** In no case can the planned Firm Demand interruption under footnote		

Organization	Yes or No	Question 2 Comment
‘b’ exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.		
Tri-State G&T	No	2. As stated previously, NERC Functional Model definitions for Planning Authorities and Transmission Planners do not include the types of activities being proposed in “Attachment 1.” As written, this standard mandates functions on functional entities that are outside those defined by the NERC Functional Model. The SDT acknowledged this by stating that “the NERC Functional Model is a guideline for activities required of cited functional entities.”As such, we still believe that obligations should not be required of entities outside of the NERC Functional Model descriptions.
Response: The SDT stands by its previous response to this comment posted for the comment period ending November 19, 2012.		
SCE&G	No	Comments previously submitted.
Response: Thank you for following the guidelines. Please see previous responses to this comment posted for the comment period ending November 19, 2012.		
Iberdrola USA	No	See comment to question 4 below.
Electric Reliability Council of Texas, Inc.	No	See response to question 4.
Response: See response to Q4.		
Entergy Services, Inc. (Transmission)	No	Attachment 1 is overly burdensome and unnecessary.
Response: The SDT believes that Attachment 1 is an appropriate response to the FERC Orders. Without specifics the SDT is unable to		

Organization	Yes or No	Question 2 Comment
provide a more detailed response to your concerns. No change made.		
Manitoba Hydro	No	Any assessment or explanation is only speculation. Is the requirement any different? Item 5 raises an expectation that footnote 12 can only be used on an interim bases - this should be clarified.
Response: The SDT believes that the changes made in this posting clarify the intent of this requirement. No change made. The SDT believes that, in general, the use of footnote ‘b’ to meet TPL performance requirements should be an interim solution. However, in certain circumstances, the SDT realizes that the solution may be permanent. The SDT does not believe that the wording only allows for interim use. If the solution is to be permanent, then that information should be disclosed as part of the stakeholder process. No change made.		
ISO New England Inc	No	Section II, 2.a, states that studies must address the estimated number and type of customers affected by Non-Consequential Load Shedding. The Transmission Planner in many cases will not be the appropriate entity to address these concerns. The Transmission Owner, Distribution Provider or Load Serving Entities would be the appropriate entities to address customer affects. Explaining effects on the “health, safety, and welfare of the community” is required under the footnote in Section II, 2.b. The same load could be shed directly as the consequence of a fault and no such assessment is required. In addition, Transmission Planners can shed radial load with no assessment of health and welfare. In addition to the practical considerations listed, once again here the standard infringes on Section 215 responsibilities where State authority over the “safety, adequacy and reliability of the electric system in that state” is mandated. This section should be deleted. Section II, requirements 3 and 4 discuss estimating frequency and duration of Non-Consequential Load Loss based on historical performance. The planning

Organization	Yes or No	Question 2 Comment
		process uses deterministic not probabilistic assessments. This section should be deleted.
Response: The SDT believes that the indicated information is easily obtained by the Transmission Planner and that, in some cases, the Transmission Planner may already have this information for other tasks and responsibilities. No change made. The SDT agrees that such information is not required in other circumstances involving allowed Consequential Load Loss. However, this situation is different in that it involves Non-Consequential Load Loss. No change made. The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. And when such decisions do not involve any aspect of BES operation or reliability, such situations would not come under the purview of footnote 'b' as standards only apply to the BES unless stated otherwise. However, in Order 693, FERC clearly stated that it has jurisdiction over matters that do involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote 'b' solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. No change made. The SDT believes that the information shown in Section II is necessary to allow stakeholders to understand the usage of footnote 'b'. No change made.		
MISO ITC JDRJC Associates LLC	No	Regarding the use of "explanation" in place of "assessment," MISO understands that the purpose of this change is to reduce the need for entities to hire expensive consultants and to incur other substantial costs in assessing demographic data and impacts on an affected area. However, as written, this word change potentially places more of a burden on responsible entities. An assessment is an analysis performed using available facts and data while an explanation implies full knowledge. MISO therefore recommends that "assessment" be retained and that a footnote explaining the meaning of that term be added. More generally, however, MISO has concerns regarding the use of a stakeholder process such as the one outlined in Attachment 1 and cannot support the Footnote or Attachment 1 at this time. Please refer to our comments under Question 4 for a more detailed description of these concerns.

Organization	Yes or No	Question 2 Comment
Response: The SDT believes that the changes made in this posting clarify the intent of this requirement. No change made. Please see response to Q4.		
Pacific gas and Electric Comapny	No	Suggest removing item 5, “A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction”. Given that the “applicable regulatory authorities or governing bodies responsible for retail electric service issues” are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?
Response: Bullet #5 does not require specific attributes of the dispute resolution process. The SDT believes that the attributes of the dispute resolution process should be defined by the entity during the development of the stakeholder process. No change made.		
SDG&E	No	
Response: Without a specific comment, the SDT is unable to respond.		
SERC EC Planning Standards Subcommittee	Yes	
Northeast Power Coordinating Council	Yes	
Southwest Power Pool Reliability Standards Development Group Kansas City Power & Light	Yes	

Organization	Yes or No	Question 2 Comment
Bonneville Power Administration	Yes	
Duke Energy	Yes	
TVA Transmission Reliability Engineering and Controls	Yes	
Western Area Power Administration - Transmission Owner	Yes	
Southern Company	Yes	
Massachusetts Attorney General	Yes	
American Electric Power	Yes	
Ameren	Yes	
WAPA-RMR	Yes	
Idaho Power Company	Yes	
Platte River Power Authority	Yes	
Tacoma Power	Yes	
ITC	Yes	
Georgia Transmission Corp.	Yes	

Organization	Yes or No	Question 2 Comment
Oncor Electric Delivery Company LLC	Yes	
Response: Thank you for your support.		

3. **Do you agree with changes contained in Section III of Attachment 1? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The SDT has responded to the individual comments and there are no technical changes proposed to the standards as a result of comments. However, to avoid confusion, the SDT has deleted the duplicative statement in Section III regarding the 75 MW limit. And, the SDT made a grammatical change in Section III changing 'does' to 'do' to correct the grammar in the applicable sentences.

Section III – "… the applicable regulatory authorities or governing bodies responsible for retail electric service issues do~~es~~ not object …"

Organization	Yes or No	Question 3 Comment
MRO NSRF	No	The NSRF believes that the standards drafting team did clarify in the webinar that the 25 MW and 75 MW footnote "b" values were separate from interruptible load, and consequential load loss and would not be counted towards the 25 and 75 MW thresholds. However, the NSRF recommends that Attachment 1 also clearly contain an explicit statement "the 25 MW and 75 MW footnote "b" values are separate from consequential load loss, interruptible load, and are not to be counted towards the 25 MW and 75 MW thresholds."
Response: The SDT does not believe that this suggestion adds any clarity. No change made.		
Hydro One Networks Inc.	No	The process presented in Section III is overly prescriptive and duplicates information not necessary for its intended purpose. As stated in Q1, we disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard, and propose alternate language in our response to Q1. If this section is required to address a review of the use of footnote 12 to ensure that there are no wide-spread adverse reliability impacts on the bulk power system, then it should be limited to the information required for that purpose. Provided there is local support for the use of Non-Consequential Load Loss under footnote

Organization	Yes or No	Question 3 Comment
		12, only information items 6 and 8 from section II are relevant for this assessment- the remainder are not required for this section and should be deleted. Items 1 and 2 complicate this section and are unnecessary. They should be replaced by a phrase such as "for those planning events where the use of footnote 12 is referenced." We disagree with the need to submit this information to the ERO for a determination of whether there are any Adverse Reliability impacts caused by the use of Non-Consequential Load Loss. This will introduce a new type of review at the ERO that will create unnecessary delays and burden, and is inconsistent with (and not required for) all of the other performance requirements in the TPL standards. Submitting the analysis to the adjacent Planning Coordinators and Transmission Planners, and any functional entity that requests it, as called for in requirement R8 of TPL-001-2 should be sufficient.
Response: The SDT does not believe the section is overly prescriptive or duplicative as described below. No change made. Please see response to Q1. The SDT believes that the information shown in Section II is necessary to allow stakeholders to understand the usage of footnote 'b'. If local regulators require additional information they can always request it. While the ERO may not need all of the information in Section II to perform its Adequate Reliability Impact evaluation, the SDT wanted to minimize the burden on entities by allowing the submittal of an information package that already existed. The ERO is aware of the proposed responsibility and has accepted this role if the industry approves. The SDT believes that it is the responsibility of the ERO to assess Adverse Reliability Impacts and is not an appropriate role for adjacent planners. No change made.		
Iberdrola USA	No	See comment to question 4 below.
Electric Reliability Council of Texas, Inc.	No	See response to question 4.
MISO ITC	No	MISO does not object to the changes made to Section III. However, more generally, MISO has concerns regarding the use of a stakeholder process such as the one outlined in Attachment 1 and cannot support the Footnote or Attachment 1 at this

Organization	Yes or No	Question 3 Comment
JDRJC Associates LLC		time. Please refer to our comments under Question 4 for a more detailed description of these concerns.
Response: See response to Q4.		
Tri-State G&T	No	3. Previously, it was commented that it is unclear how section III of "Attachment 1" would be applied to entities that only deliver wholesale electric service and not retail electric service. The response provided by the SDT stated the following: The SDT believes that the wholesale customer will be one of the stakeholders included in the process and any use of footnote must go through the stakeholder process. No change made. If the wholesale customer is one of the stakeholders, the standard needs to add wholesale customers into the language as part of Attachment I. For example, it should read as follows: Coordinator must ensure that the applicable regulatory authorities, wholesale customers, or governing bodies responsible for retail electric service issues does not object to the use of Firm Demand interruptions under footnote 'b'...
Response: The SDT believes that the planning entity has the best understanding of who an affected stakeholder will be and that any attempt to codify a list of such stakeholders in the proposed standards could lead to errors due to the necessity of having to adopt a one size fits all approach. No change made.		
Western Area Power Administration - Transmission Owner	No	See answer to Question 1.
WAPA-RMR	No	See response to Question 1.
Platte River Power Authority	No	See answer to Question 1.
Response: See response to Q1.		

Organization	Yes or No	Question 3 Comment
Massachusetts Attorney General	No	Don't buy the 75 MW or the 25 MW thresholds.
Response: The SDT established the values based on the results of the Section 1600 data request. While the SDT considered other values, the data collected did not justify such an action. No change made.		
Entergy Services, Inc. (Transmission)	No	Attachment 1 is overly burdensome and unnecessary.
Response: With no specifics provided, the SDT is unable to respond further. However, the SDT does not believe the process to be overly burdensome or unnecessary. No change made.		
SCE&G	No	Comments previously submitted.
Response: Thank you for following the guideline. Please see previous responses to this comment posted for the comment period ending November 19, 2012.		
Independent Electricity System Operator	No	The process presented in Section III is overly prescriptive and requires information not necessary to the intended purpose. As stated in Q1, we disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard, and propose alternate language as stated in Q1 comments and supporting reasons. If this section must deal with a review of the use of footnote 'b'/'12' to ensure that there are no widespread adverse reliability impacts on the bulk power system, then it should be limited to the information required for that purpose. Provided there is local support for the use of Non-Consequential Load Loss under footnote 'b'/'12', only information items 6 and 8 from section II are relevant for this assessment-the remainder are not required for this section and should be deleted. The use of footnote 'b'/'12' should not be limited to the Near-Term Planning Horizon. We propose that the words "in Year One of the Planning Assesssment" be deleted.

Organization	Yes or No	Question 3 Comment
		Items 1 and 2 complicate this section and are unnecessary. They should be replaced by a phrase such as “for those planning events where the use of footnote ‘b’/’12’ is referenced”. We disagree with the need to submit to the ERO for a determination of whether there are any adverse reliability impacts caused by the use of Non-Consequential Load Loss. This will introduce a new type of review at the ERO that will create unnecessary delays and burden, and is inconsistent with and not required for all of the other performance requirements in the TPL standards. Submitting the analysis to the adjacent Planning Coordinators and Transmission Planners, and any functional entity that requests it, as called for in requirement R8 of TPL001-2 should be sufficient.
Response: The SDT does not believe the section is overly prescriptive or duplicative as described below. No change made. Please see response to Q1. The use of the footnote is not limited to the Near-Term Transmission Planning Horizon since the main body of the footnote states that the footnote may be utilized “… throughput the planning horizon…”. An entity has the freedom to make a business decision concerning the use of footnote ‘b’ compared to other alternatives. An entity is free to determine when they want to assure that the local regulator does not object but it must do so no later than Year One of the Planning Assessment. No change made. The SDT believes that items 1 and 2 are needed to describe when an entity must assure that there are no regulatory objections. No change made. While the ERO may not need all of the information in Section II to perform its Adequate Reliability Impact evaluation, the SDT wanted to minimize the burden on entities by allowing the submittal of an information package that already existed. The ERO is aware of the proposed responsibility and has accepted this role if the industry approves. The SDT believes that it is the responsibility of the ERO to assess Adverse Reliability Impacts and is not an appropriate role for adjacent planners. No change made.		
Pacific gas and Electric Comapny	No	We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative

Organization	Yes or No	Question 3 Comment
		process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the "applicable regulatory authorities or governing bodies responsible for retail electric service issues".
Response: The SDT believes that the information shown in Section II is necessary to allow stakeholders to understand the usage of footnote 'b'. No change made.		
SDG&E	No	
Response: Without a specific comment, the SDT is unable to respond.		
ISO New England Inc		The footnote states "Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues does not object to the use of Non-Consequential Load Loss under footnote 12 if either...". Section 215 of the Federal Power Act clearly delineates Federal, State and Local authority. State and Local requirements should not be introduced into a NERC standard. In addition to the jurisdictional issues, proving that the "applicable regulatory authority or governing body" does not object is more difficult than proving that they simply approved the use of non-consequential load loss. The SDT should remove all references to State and Local authority from the standard. Overall, the order of Section III is also notable. During year, two through ten of the overall planning horizon the standard allows for Non-Consequential Load Loss without approval. In the first year of the assessment, approval becomes required for Non-Consequential Load Loss. At this point, it is too late to allow for any other alternative.

Organization	Yes or No	Question 3 Comment
		The Regional Entities with NERC oversight perform periodic audits and require self-certification of the planning process. By virtue of the audit and self-certification process, NERC has the ability to monitor the use of Non-Consequential Load Loss in planning assessments. State and Local approval of practices called for in ERO Standards is inappropriate. In addition to being notable for the year one timing, Section III seems incomplete. In the case where there is objection to Non-Consequential Load Shedding, the process appears to end without resolution.
Response: In Order 693, FERC clearly stated that it has jurisdiction over matters that involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote 'b' solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. The footnote does not place requirements on local regulators but rather provides them an opportunity to participate in the stakeholder process. No change made. An entity has the freedom to make a business decision concerning the use of footnote 'b' compared to other alternatives. An entity is free to determine when they want to assure that the local regulator does not object but it must do so no later than Year One of the Planning Assessment. No change made. Without the details now contained in the proposed footnote, there is no guarantee that NERC would have the information to monitor the use of Non-Consequential Load Loss. The footnote does not place requirements on local regulators but rather provides them an opportunity to participate in the stakeholder process. No change made. If there is an objection by the regulators, then an entity cannot utilize footnote 'b' as proposed as part of the Corrective Action Plan for Year One. No change made.		
Ameren	Yes	We find no substantive changes to section III, and still believe that no objection from a regulatory body requires, at a minimum, a tacit approval.
Response: The SDT believes that there are a variety of practices employed by regulatory bodies. Therefore, it is determined by the planning entity and the applicable regulatory bodies as to how to show 'no objection'. No change made.		

Organization	Yes or No	Question 3 Comment
SERC EC Planning Standards Subcommittee	Yes	Change "does" to "do" in the last sentence of the first paragraph and in the first sentence of the last paragraph in Section III of Attachment 1.
Response: The SDT agrees and has made the suggested grammatical change. **Section III** – "… the applicable regulatory authorities or governing bodies responsible for retail electric service issues do~~es~~ not object …"		
Northeast Power Coordinating Council	Yes	
Southwest Power Pool Reliability Standards Development Group Kansas City Power & Light	Yes	
Bonneville Power Administration	Yes	
ACES Standards Collaborators Brazos	Yes	
Duke Energy	Yes	
TVA Transmission Reliability Engineering and Controls	Yes	
Southern Company	Yes	
American Electric Power	Yes	

Organization	Yes or No	Question 3 Comment
Idaho Power Company	Yes	
Tacoma Power	Yes	
ITC	Yes	
Georgia Transmission Corp.	Yes	
Oncor Electric Delivery Company LLC	Yes	
Response: Thank you for your support.		

4. **If you have any other comments on this Standard that you haven't already mentioned above, and that are not simply reiterating previous comments that the SDT has already responded to, please provide them here:**

Summary Consideration: The SDT has responded to the individual comments and there are no changes proposed to the standards as a result of comments. However, the SDT did uncover a typo that has been corrected as shown below.

TPL-002-1c: footnote 'b' – "…For purposes of this footnote, the following are not counted as Firm Demand~~t~~: (1) …"

Organization	Yes or No	Question 4 Comment
Hydro-Quebec TransEnergie	No	HQT still considers that the non application of footnote 12 to categories P2 (breaker fault), P4 (stuck breaker) and P5 (failure of a non redundant relay) is not correct, when the footnote is applied to other categories such as P3, P6 and P7 (loss of double-circuit lines). The SDT has indicated that the applicability of footnote 12 to categories P2, P4 and P5 is not included in Project 2012-11. However, looking at related Project 2006-02 where footnote 12 was brought up to Table 1, the matter of applicability was not discussed in detail and the SDT did not clearly explain why Non-Consequential Load Loss was not allowed for contingencies less frequent than those for which it is allowed (internal breaker faults or stuck breakers are less probable than double-circuit line faults). Discussion on this matter should not be dismissed.
Response: Table 1 in the proposed TPL-001-2 was previously approved by industry through the standards development process. The Board of Trustees has also previously approved this proposed standard. Discussions on the applicability of footnote 12 in that standard were held during Project 2006-02 and are not part of this proceeding. No change made.		
Bonneville Power Administration	No	
Duke Energy	No	

Organization	Yes or No	Question 4 Comment
American Electric Power	No	
SDG&E	No	
Idaho Power Company	No	
Platte River Power Authority	No	
SCE&G	No	
Oncor Electric Delivery Company LLC	No	
Pacific gas and Electric Comapny	No	
Response: Without a specific comment, the SDT is unable to respond.		
ACES Standards Collaborators Brazos	Yes	(1) In regard to the changes relating to Demand-Side Management, we agree with the wording, "For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of a Contingency, or (2) Interruptible Demand or Demand-Side Management Load." However, the most recent change has created some confusion by replacing "or" with "and" that potentially and inadvertently may exclude the use of DSM in all locations but on the facilities removed from service. This would render DSM ineffective. Now, the both (1) and (2) must occur in order to not be counted as Firm Demand. We recommend changing the wording back to "or" so each option (1) OR (2) is independently excluded from Firm Demand for footnote b. Connecting the options with the word "and" changes the meaning and requires entities to meet both option (1) and option (2) to be excluded from Firm Demand. Demand directly served by the Elements removed from service as a result of a Contingency should be

Organization	Yes or No	Question 4 Comment
		excluded, as should Interruptible Demand or Demand-Side Management Load regardless of its location. A registered entity does not need to have both for the exclusion. (2) Thank you for the opportunity to comment.
Response: The SDT does not agree that 'and' excludes the use of both items 1 and 2 since this is a list of options. However, while researching your suggestion, the SDT discovered a typo in the language when the previous red-line was converted to a clean copy. This has been corrected as shown. **TPL-001-2c: footnote 'b'** – "…For purposes of this footnote, the following are not counted as Firm Demand~~t~~: (1) …"		
Hydro One Networks Inc.	Yes	As previously stated in our response to Question #1, Hydro One would like to reiterate our position presented during the initial comment period. We believe that the SDTs response to our initial comments did not correctly address the issues because it did not recognize the Reliability Standards framework that is effective in the Province of Ontario and possibly other Canadian provinces.
Response: Please see the response to Q1.		
MISO ITC JDRJC Associates LLC	Yes	As previously stated, it is the general intent of the existing TPL-002-1 standard and proposed TPL-001-2 standard to not rely on any shedding of Non-Consequenital Load to meet a single contingency event. Accordingly, MISO submits that footnote b of TPL-002-1 and footnote 12 of TPL-001-2 should be struck. However, in the event that the footnotes in question are not eliminated, the footnote should be narrowly focused only on those situations for which the original footnote was developed, i.e., the interruption of service to radial customers or some local area Network customers connected to or supplied by the Faulted element or by the affected area, where the overall reliability of the interconnected transmission system is not impacted. MISO therefore proposes the following alternate language for footnote b and footnote 12 to ensure it is not misapplied:"An objective of the planning process is to avoid Non-Consequential Load Loss following Contingency

Organization	Yes or No	Question 4 Comment
		events. In limited circumstances, Non-Consequential Load Loss may be needed within the planning horizon to ensure that BES performance requirements are satisfied. However, Non-consequential Load shed cannot be used to avoid cascading outages or to maintain system stability. Non-consequential load shed also cannot be used to avoid a thermal loading or voltage limit violation on an extra high voltage (EHV) facility. When Non-Consequential Load Loss is utilized within the transmission planning horizon to address BES performance requirements, such interruption cannot exceed 75 MW and is limited to the following circumstances: o Non-consequential Load shed is allowed for load served by a radial transmission line to avoid voltage limit violations on the radial transmission line following a single contingency event. o Non-consequential load shed is allowed for load within a local area served by not more than two Transmission Circuits and/or Transformers to avoid a thermal loading issue or voltage issue within the local area, including the Transmission Circuits and/or Transformers directly supplying the local area, for a loss of a single element within the local area, including one of the Transmission Circuits or Transformers directly supplying the local area, so long as there are no thermal loading or voltage violations outside the local area." MISO believes the language above would ensure the continuing reliability of the Bulk Electric System by limiting load shed and violations that require load shed to radial areas or areas that would be served radially following the single contingency. In addition, MISO has significant concerns regarding use of a stakeholder process to determine if non-conseqeuntial load shedding is appropriate following a single contingency event, as expressed in MISO's comments on previous drafts of this Project. In particular, MISO has concerns regarding whether such a stakeholder process could be sufficiently open and transparent given the many, competing interests of the responsible entity and affected stakeholders. Without such sufficient openness and transparency, it is likely that stakeholder processes will not result in consistent determinations of the appropriateness of the application of footnote b in NERC TPL-002-1 and/or footnote 12 in TPL-001-2. Stated differently, MISO is concerned that such stakeholder processes will always be subject to the

Organization	Yes or No	Question 4 Comment
		biases of the participating parties, with the sheer number of parties determining the outcome of the process. As an example, should a particular process be dominated by parties that may be responsible for payment of upgrades but that are not impacted by the alternative load shed, those stakeholders impacted by the alternative load loss would be relegated to a minority position, resulting in majority-imposed stakeholder decisions to shed load. On the other hand, if the stakeholder process is limited to only the stakeholders directly impacted by the proposed load shed, to the extent those stakeholders pay only a small part of the upgrade costs, they will always choose to avoid load shed - even if such decision requires a potentially costly upgrade. Consequently, MISO has concerns that the inclusion of a requirement for a fair and impartial stakeholder process to determine if and when load shed is acceptable to assist in satisfying a single contingency standard is not realistically attainable. MISO therefore recommends that Attachment I be eliminated and that the footnotes either be eliminated or replaced with the modified version above.
Response: The SDT believes that the suggested language adopts a one-size fits all approach that is not conducive to a continent-wide standard. The footnote allows for circumstances outside of the suggested language scenarios, as well as those described in the suggestion, to be resolved utilizing an open and transparent process. No change made. The SDT believes that the inclusion of stakeholders including regulators provides an appropriate method for addressing the issues that the commenter has raised. No change made.		
BC Hydro	Yes	BC Hydro appreciates the efforts of the SDT in revising standards TPL-002-1c - System Performance Following Loss of a Single BES Element (footnote b) and TPL-001-2a - Transmission System Planning Performance Requirements (footnote 12). BC Hydro votes YES in support of this ballot and wishes to provide the following two comments: 1.At this time BC Hydro has concerns about the level of stakeholder consultation that might be required as a result of the implementation of this standard and will bring this concern to the attention of our regulator if necessary. 2.At this time BC Hydro has concerns about the instances for which regulatory

Organization	Yes or No	Question 4 Comment
		review of non-consequential load loss under footnote 12 is required and will discuss those with our regulator if necessary.
Response: The SDT appreciates your overall support. In addition, please see the changes shown in Q1 for non-US registered entities.		
Central Lincoln Flathead	Yes	Central Lincoln has not paid much attention to this standard, since it is not applicable to this entity's registered functions. However, we are disturbed by the direction the standard is taking. The slides from the recent webinar (http://www.nerc.com/docs/Standards/dt/footnoteb_webinar_20130108_final.pdf) state that "The 75 MW cap will require construction of major Transmission projects." This is in direct conflict with the definition of "reliability standard" as provided in section 215 of the FPA where it states "...the term does not include any requirement to enlarge such facilities or to construct new transmission capacity..." The webinar slide does offer alternatives to construction, but we don't see those providing any reliability benefit. Some of the suggestions apparently only relate to contract language, which cannot possibly relate in any way to "reliable operation" as defined in section 215. Central Lincoln is is concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal power Act and into customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions.
Response: The statement from the January 8, 2013 webinar is a concern that industry had raised during the course of the project, which the SDT had captured on a slide in order to respond to the concern during the webinar. The SDT pointed out that building is not the sole source of remedy for the situation and provided specific examples in the webinar (http://www.nerc.com/docs/Standards/dt/footnoteb_webinar_20130108_final.pdf (slide 13)). In Order 693, FERC clearly stated that it has jurisdiction over matters that do involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote 'b' solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. No change made.		
Electric Reliability Council of Texas, Inc.	Yes	ERCOT believes that the revisions to the footnote b attachment are an improvement from the previous version. However, ERCOT does not believe that the

Organization	Yes or No	Question 4 Comment
		SDT provided a technical rationale for disagreeing with the comments that we previously submitted. We fundamentally disagree with the approach of defining a stakeholder process in the attachment to a footnote in a reliability standard. While footnotes and attachments have been used in other standards we believe that this application is not appropriate. ERCOT believes that the footnote should be removed altogether as it does not meet the objectives of FERC Order 693. We also believe that FERC did not mandate that a stakeholder process be used. As stated in the January 8 NERC Industry Webinar, 90% of planning entities have not used the existing footnote b over a planning horizon of 13 years. To incorporate an attachment to a footnote with a complicated and prescriptive stakeholder process to address a few instances seems to be a least common denominator approach to planning which is opposed to FERC's direction. Consistent with the approach of TPL-001-2, ERCOT recommends raising the bar on reliability and removing the footnote from the standard.
Response: The SDT used the Board of Trustees approved standard as a starting point for this draft. FERC remanded the standard; not because it contained a stakeholder process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. The use of footnotes and attachments is an acceptable mechanism for use in Reliability Standards and both mechanisms have been used before. No change made. The SDT believes that special circumstances may exist where such actions as described in footnote 'b' are appropriate to meet the performance requirements of TPL. The footnote allows for such circumstances to exist in a controlled and prescribed environment where such usages can be discussed and resolved in an open and transparent process. No change made.		
Southern Company	Yes	Footnote b contains no technical basis for allowing load dropping. It is completely based on an administrative procedure. This is not responsive to paragraphs 17 and 32 of the FERC remand order. A technical basis has to be proposed. The "temporarily radial" concept that was proposed in earlier drafts will address this problem. It will give a technical basis for when load dropping would be allowed. If a technical basis is developed like FERC requires, then there is no need for a

Organization	Yes or No	Question 4 Comment
		stakeholder process. The stakeholder process is not a bright line criteria which can be enforced; it will change depending on the make-up of stakeholders and therefore create inconsistencies across the grid. This approach should never be used in a reliability standard. NERC adopted the ANSI standard process as the bench mark in developing its reliability standards. ANSI does not use stakeholder processes. We propose that the stakeholder process be eliminated. Create a technical basis for when load dropping can be utilized. Keep the 75 MW maximum amount of load that can be dropped.
Response: The SDT believes that the proposed approach is responsive to the Remand Order since it contains quantitative criteria and a more well-defined stakeholder process. The temporary radial concept was discussed by the SDT but abandoned due to industry comments that pointed to the difficulties in adopting this concept on a continent-wide basis. The attachment is enforceable as a clear set of expectations has been described. The conclusions reached as a result of following the stakeholder process may be different due to local configurations, constraints, and expectations of applicable regulatory bodies. No change made.		
WAPA-RMR	Yes	I believe that the 75 MW limit is abetrary and could be too low given particular circumstances, like the maginitude of recent load growth in the area, regulatory hurdles in building new transmission, etc. I also believe that the Attachment 1 stakeholder process is not needed, since it is already covered by the FERC Ordered 890 planning process.
Western Area Power Administration - Transmission Owner	Yes	Western believes that the 75 MW limit is arbitrary and could be to low given particular circumstances, like the magnitude of recent load growth in the area, regulatory hurdles in building new transmission, etc. We also believe that the Attachment 1 stakeholder process is not needed, since it is already covered by the FERC Order 890 process.
Response: The SDT established the limit based on the results of the Section 1600 data request which clearly pointed to a 75 MW limit. While the SDT considered a higher limit value, the data collected does not justify such an action. The SDT used the Board of Trustees approved standard as a starting point for this draft. FERC remanded the standard; not because it contained a stakeholder		

Organization	Yes or No	Question 4 Comment
process, but because the process was not well defined, did not include quantitative and qualitative criteria for allowing curtailment of Firm Demand and did not assure that BES reliability would be maintained. The balloted draft added detail and specificity to the already approved approach. The use of footnotes and attachments is an acceptable mechanism for use in Reliability Standards and both mechanisms have been used before. No change made. The phrase in Section I: "The responsible entity can utilize an existing process or develop a new process" was designed to allow an entity to use an existing process as long as it meets the requirements shown in Attachment 1. No change made.		
Entergy Services, Inc. (Transmission)	Yes	If Attachment 1 must remain, Entergy would support the SERC PSS suggestion to limit the application of Attachment 1 (the stakeholder process) to only those situations where the non-consequential load at risk is above 25MW.
Response: As approved by the Board of Trustees, all utilizations of footnote 'b' required the use of the stakeholder process. The current proposal does not, and should not, deviate from this premise. The Remand Order stated that quantitative criteria needed to be supplied for the stakeholder process and the current proposal provides that criteria. No change made.		
Manitoba Hydro	Yes	Manitoba Hydro cannot support the Footnote B attachment which imposes a stakeholder process not required in Manitoba.
Response: The open and transparent stakeholder process is a new requirement for all entities in response to the need to clarify footnote 'b'. No change made.		
seattle city light	Yes	SCL abstains from voting on the revisions to footnote "b" in TPL-002-1c and the corresponding footnote 12 of TPL-001-2.Â SCL is concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal power Act and into customer service issues that are better served by, and under the jurisdiction of,Â state and local utility boards and commissions (for details on SCL's concerns please see the comments submitted during the initial ballot).Â However, in the spirit of moving this process forward, SCL will not vote against the revised footnotes.
Public Utility District No.1 of	Yes	The Public Utility District No.1 of Snohomish County will abstain from voting on the

Organization	Yes or No	Question 4 Comment
Snohomish County		revisions to footnote "b" in TPL-002-1c and the corresponding footnote 12 of TPL-001-2. The Public Utility District No.1 of Snohomish County is concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal power Act and into customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions (for details on the Public Utility District No.1 of Snohomish County's concerns please see the comments submitted during the initial ballot). However, in the spirit of moving this process forward, the Public Utility District No.1 of Snohomish County will not vote against the revised footnotes.
ISO New England Inc		In summary, this standard as proposed has misplaced jurisdictional authority under Section 215 of the Federal Power Act. The removal of references to State and Local authorities in the standard is required.
National Grid	Yes	We are accepting the standard as written because our current practices are better then the prescribed maximum limit. However, we believe the appropriate limit should be determined on a case by case basis with the state regulator input. This standard as written, does give us the flexibility to do this.
Response: The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. And when such decisions do not involve any aspect of BES operation or reliability, such situations would not come under the purview of footnote 'b' as standards only apply to the BES unless stated otherwise. However, in Order 693, FERC clearly stated that it has jurisdiction over matters that do involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote 'b' solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. No change made.		
New Brunswick System Operator		We do not agree with setting a MW limit for non-consequential load loss. The allowable amount should be determined and approved by the jurisdiction of the area(s) whose load is affected. The intent of the TPL standard and this footnote is to ensure that if non-sequential load loss is accounted for or relied up to ensure BES reliability (as assessed in the planning horizon), that such a decision needs to be

Organization	Yes or No	Question 4 Comment
		approved by the appropriate jurisdiction
Response: Please see the changes shown in Q1 to account for jurisdictional differences for non-US registered entities.		
MRO NSRF	Yes	Some entities remain concerned over a potential conflict and mismatch of impacts introduced by Section III and the inclusion of non-regulated stakeholders versus NERC regulated entities. There was not a FERC directive to include section III. Section III overreaches the intent of the FERC order and the SAR to meet the FERC directive. The drafting team should show the specific FERC requirement and words in Order 693 that requires non-NERC regulatory reviews. The drafting team technically responded to a request that Section III be removed, but avoided the the fundamental issue. The fact that some existing non-NERC regulatory bodies may already have a consistent practice is not a reason to include non-NERC entities into a NERC framework. This creates a fundamental mismatch between NERC regulated entities that must follow NERC standards and stakeholders that are not compelled by NERC requirements. If Section III is not deleted, it is recommended that wording be added to allow the existing FERC Order 890 stakeholder meeting process be used to meet Attachment 1. Regulators attend these meetings and all stakeholders (including regulators) could be asked for their objections. If there was no response or a "lack of dissent", this would be documented as meeting Attachment 1 to allow the use of footnote "b" without additional special procedures.
Response: The phrase in Section I: "The responsible entity can utilize an existing process or develop a new process" was designed to allow an entity to use an existing process as long as it meets the criteria shown in Attachment 1. No change made.		
Iberdrola USA	Yes	The reasons for the "negative" vote are enumerated in our prior comments. In summary: 1. Attachment 1 is cumbersome and inappropriate, and should be stricken entirely. 2. All non-consequential load loss for all single-element contingencies should be temporary, with an action plan to avoid such load loss in the future.

Organization	Yes or No	Question 4 Comment
		3. All actions following single-element contingencies should be an attempt to restore lost customer service, not interrupt more customers.
Response: The transparency provided by the stakeholder process will meet the regulatory guidance provided on this issue. The limited use of footnote 'b' as shown by the data collected in response to the Section 1600 data request indicates relatively few instances where footnote 'b' would be used. For this reason, the SDT believes that the proposed approach strikes the right balance. . No change made. The SDT agrees that this is often the normal course of action. However, the SDT has not mandated this course of action since there could be circumstances that may arise where the continued use of footnote 'b' may be the best over-all solution for all concerned. No change made. The SDT believes that special circumstances may exist where such actions as described in footnote 'b' are appropriate to meet the performance requirements of TPL. The footnote allows for such circumstances to exist in a controlled and prescribed environment where such usages can be discussed and resolved in an open and transparent process. No change made.		
Southwest Power Pool Reliability Standards Development Group Kansas City Power & Light	Yes	Under section II items 3 and 4 the wording (frequency and duration) seems to implicate that the planners will be determining these events in a probabilistic manor. If the probability of these events is anything other than 0 planners will have to accommodate for those events in their planning assessments regardless of how small the probability is for that event.
Response: The SDT does not agree that the wording requires a probabilistic determination. The planning method utilized to make the determination is left up to the planner however this information is necessary to allow stakeholders to understand the usage of footnote 'b'. No change made.		
ITC	Yes	While ITC is voting yes for this "successive ballot", we are doing so in the interest of ensuring that TPL 001-2 becomes fully effective as soon as possible. TPL001-2 is a major improvement to previous standards and insuring it becomes fully effective is important to ITC and the industry. However, we have concerns that we would like to be noted. Because footnote B has been highlighted and expanded, there is the possibility of future "unintended consequences". It is highly likely that interveners

Organization	Yes or No	Question 4 Comment
		or others may attempt to stop or slow down needed corrective action plans, that do not rely on load shedding, by suggesting that planners use this stakeholder process before proposing projects. We suggest both NERC and FERC be prepared to deal with these unintended consequences. We also concur in entirety with the comments MISO is proposing to make for this project. They are consistent with past comments ITC has made and do discuss in some detail the potential "unintended consequences" this detailed footnote may cause.
Response: The SDT believes that special circumstances may exist where such actions as described in footnote 'b' are appropriate to meet the performance requirements of TPL. The footnote allows for such circumstances to exist in a controlled and prescribed environment where such usages can be discussed and resolved in an open and transparent process. No change made.		
Xcel Energy	Yes	While we are not satisfied with the responses to our previous comments, we have chosen to not reiterate them here. Instead, we feel that the need to continue with any modification to Footnote b seems moot considering FERC's recent approval of the revised BES definition. Specifically, we believe exclusions E1 and E3, regarding radial systems and local networks, resolves FERC's original directive on ambiguity with footnote b. We recommend the team consider abandoning this project, and request that NERC staff request relief from FERC on the related directives, as they have been overcome by the modified BES definition.
Response: The SDT believes that there may be portions of the BES, even with the proposed revised BES definition, where it may still be appropriate to address performance issues using footnote 'b' for Non-Consequential Load Loss. No change made.		
Independent Electricity System Operator		(1) The IESO reiterate its support for allowing load interruption for a single contingency with sufficient review/oversight and under acceptable conditions, including no widespread adverse impact on the reliability of the interconnected bulk power system. The reliability aspects (BES performance requirements) should be reviewed for acceptability by the adjacent Planning Coordinators and Transmission Planners. However, issues pertaining to economics or externalities which may not be directly reliability-related are always available for review and

Organization	Yes or No	Question 4 Comment
		debate by the stakeholders via the regulatory processes and subject to approval by the regulatory authority of each jurisdiction (including those in Canada and Mexico). (2) Furthermore, we request that Table 1 of TPL-001-3 (previous TPL-001-2 approved by NERC BOT) be corrected for EHV contingencies in P2, P4 and P5 categories to allow the application of footnote ‘b’/’12’ that is allowed for the P1 events. Events in P2, P4, and P5 can involve more elements and can be more onerous and stressful to the system than the P1 events, and if use of footnote ‘b’/’12’ is permitted in the less stressful P1 events, it should also be permitted in P2, P4 and P5 events. There continues to be confusion as to this inconsistency, and to how this is to be applied (as discussed at the last webinar). (3) We suggest that NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve it. Accordingly, we believe that the focus of footnote ‘b’, and footnote 12 should be that interruption of load must not have a widespread, adverse impact on the reliability of the interconnected bulk power system. A continent-wide standard should not concern itself with the reliability of supply or supply continuity for local load, as that is the responsibility of the applicable regulatory authority or its agencies responsible for local transmission and retail service over the load to be curtailed. As mentioned above, NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve it. In this regard, we believe that Attachment 1 is not necessary because it prescribes a process which goes beyond the outcome of the standard and dictates how stakeholdering must be carried out. The individual jurisdiction should establish the process for ensuring compliance with the standard and decide to what extent a stakeholdering process is necessary to establish the acceptable level of load rejection for the area in a manner consistent with local transmission established service levels. (4) The process presented in Section I is overly prescriptive. If a section that prescribes the principles of a stakeholder process is required, then for Canadian entities this section should simply state that any threshold should be established in

Organization	Yes or No	Question 4 Comment
		a manner consistent with other service levels that apply to local transmission and retail service for the load to be curtailed, as described in Q1 and for the reasons stated therein. Corrective action plans can rarely be implemented in a one-year time frame, and in some cases, limited use of Non-consequential Load Loss will be preferable to unaffordable transmission enhancements, therefore we believe that the use of footnote ‘b’/’12’ should not be limited to the Near-Term Transmission Planning Horizon. We propose that the phrase “the Near-Term Transmission Planning Horizon of” be deleted from the opening paragraph.
Response: The SDT believes that it is the responsibility of the ERO to assess Adverse Reliability Impacts and is not an appropriate role for adjacent planners. The proposed stakeholder process allows all stakeholders, including regulators, will have the necessary information required for the indicated reviews. No change made. Table 1 in the proposed TPL-001-2 was previously approved by industry through the standards development process. As shown by this approval, the SDT and the industry disagree that there is a technical irregularity in Table 1. The Board of Trustees has also previously approved this proposed standard. Discussions on the applicability of footnote 12 in that standard were held during Project 2006-02 and are not part of this proceeding. No change made. The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. And when such decisions do not involve any aspect of BES operation or reliability, such situations would not come under the purview of footnote ‘b’ as standards only apply to the BES unless stated otherwise. In addition, please see the changes shown in Q1 to address jurisdictional concerns for non-US registered entities. No change made. Please see the changes shown in Q1 to address jurisdictional concerns for non-US registered entities. The use of the footnote is not limited to the Near-Term Transmission Planning Horizon since the main body of the footnote states that the footnote may be utilized “… throughput the planning horizon…”. No change made.		
SERC EC Planning Standards Subcommittee		We continue to recommend that up to 25 MW of planned interruption be allowed without triggering the need for a stakeholder process. We believe that this simplification would be less burdensome and would enhance industry acceptance of the revision, while still meeting regulatory guidance. The comments expressed

Organization	Yes or No	Question 4 Comment
		herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
TVA Transmission Reliability Engineering and Controls		We recommend that up to 25 MW of planned interruption be allowed without triggering the need for a stakeholder process. We believe that this simplification would be less burdensome and would enhance industry acceptance of the revision, while still meeting regulatory guidance.
Response: As approved by the Board of Trustees, all utilizations of footnote ‘b’ required the use of the stakeholder process. The current proposal does not, and should not, deviate from this premise. The Remand Order stated that quantitative criteria needed to be supplied for the stakeholder process and the current proposal provides that criteria. No change made.		
Tacoma Power		While Tacoma Power appreciates NERC's attempt to address both footnotes with the same drafting team, Tacoma Power is voting negative on the revisions to footnote "b" in TPL-002-1c and the corresponding footnote 12 of TPL-001-2. However, Tacoma Power would vote affirmative if a re-circulation ballot was limited strictly to footnote "b" in TPL-002-1c. TPL-001-2 considered new types of outages not considered by TPL version 1, such as P2-1. Although TPL-001-2 was approved by the industry, the proposed modifications to footnote 12 in TPL-001-2 are significantly more onerous than footnote 12 in TPL-001-2. Furthermore, since TPL-001-2 is not yet enforceable, some Transmission Planners still do not realize that automatic relay actions are considered Non Consequential Load Loss. In addition, Tacoma Power identified over 100 MW of load in multiple locations that would be shed in accordance with footnote 12 in TPL-001-2. Unfortunately, the structure of the Section 1600 data request did not allow for the submittal of footnote 12 related data. Since it is clear that the potential impact of the footnote 12 revision has not been addressed due to the compressed timeline, Tacoma Power believes that by separating the two standards, NERC can meet the FERC mandated deadline for footnote b while still continuing the drafting process to achieve true industry consensus on footnote 12. Please note that FERC orders 693 and 762 require

Organization	Yes or No	Question 4 Comment
		addressing only footnote "b" by the using the Expedited Standards Development Process. Earlier FERC orders discuss "single contingencies" as type Category B in TPL-002-1; FERC has not addressed Non Consequential Load Shedding for the lower probability "single contingencies" (i.e. P2-1) in TPL-001-2. Approving the revisions to footnote 12 would result in negligible reliability gains at an unreasonable cost for customers on the fringes of the power system, without affording local jurisdictional cost benefit analysis. Tacoma Power is also concerned that the revised language oversteps the bounds of the "reliability standard" definition under Section 215 of the Federal Power Act. These revisions tread on customer service issues that are better served by, and under the jurisdiction of, state and local utility boards and commissions. For details on Tacoma Power's concerns please see the comments submitted during the initial ballot. However, in the spirit of moving this process forward, Tacoma Power would vote to approve the revisions to solely TPL-002-1c if balloted separately from TPL-001-2.Tacoma Power appreciates the opportunity to provide comments, and thanks you for consideration of our comments.
Response: Any information gleaned from a Section 1600 data request based on application of footnote 12 would have been speculative prior to the implementation of the new TPL-001-2. From the review of the comments submitted, it does not appear that separation of the standards would be a consensus view. No change made. The proposed solution allows for input and participation at every step of the process by local jurisdictional authorities. And when such decisions do not involve any aspect of BES operation or reliability, such situations would not come under the purview of footnote 'b' as standards only apply to the BES unless stated otherwise. However, in Order 693, FERC clearly stated that it has jurisdiction over matters that do involve BES operations and reliability. Furthermore, these orders mandate the ERO to write standards and requirements to address all aspects of BES operations and reliability in support of these goals. The proposed footnote 'b' solution acknowledges these facts and is an appropriate response to subsequent FERC directives on this matter. No change made.		

END OF REPORT

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR approved by SC in May 2012.
2. Initial comment period July 31, 2012 – August 29, 2012.
3. Initial ballot and comment period October 5, 2012 – November 19, 2012.
4. Successive ballot and comment period December 10, 2012 – January 11, 2013

Proposed Action Plan and Description of Current Draft:

The SDT is working to address FERC's remand of the proposed clarification of TPL-002, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System. That footnote is captured here as footnote 12.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Recirculation ballot	January 2013
2. BOT approval	February 2013

Definitions of Terms Used in Standard

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

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-3**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-3, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-3:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.

- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past

studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the

use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

<table>
<tr><th colspan="2">Table 1 – Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">Steady State & Stability
For all extreme events evaluated:
a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
b. Simulate Normal Clearing unless otherwise specified.</td></tr>
<tr><td>Steady State
1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
a. Loss of a tower line with three or more circuits.[11]
b. Loss of all Transmission lines on a common Right-of-Way[11].
c. Loss of a switching station or substation (loss of one voltage level plus transformers).
d. Loss of all generating units at a generating station.
e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
a. Loss of two generating stations resulting from conditions such as:
i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
ii. Loss of the use of a large body of water as the cooling source for generation.
iii. Wildfires.
iv. Severe weather, e.g., hurricanes, tornadoes, etc.
v. A successful cyber attack.
vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
b. Other events based upon operating experience that may result in wide area disturbances.</td>
<td>Stability
1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
e. 3Ø internal breaker fault.
f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances</td></tr>
</table>

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, &

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community

3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
    a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
    b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	03/17/2001	Revision of TPL-001-0 to modify only Table 1 footnote b. Approved by Board of Trustees	Project 2006-02 – revision to address FERC directive
2	To be Determined	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2a	February 2013	Address remand of proposed footnote 'b' pursuant to FERC Order RM06-16-009	Revised

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR approved by SC in May 2012.
2. Initial comment period July 31, 2012 – August 29, 2012.
3. Initial ballot and comment period October 5, 2012 – November 19, 2012.
4. Successive ballot and comment period December 10, 2012 – January 11, 2013

Proposed Action Plan and Description of Current Draft:

The SDT is working to address FERC's remand of the proposed clarification of TPL-002, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single Contingency occurs on a Transmission System. That footnote is captured here as footnote 12.

Future Development Plan:

Anticipated Actions	Anticipated Date
~~Successive ballot~~	~~December 2012~~
1. Recirculation ballot	January 2013
2. BOT approval	February 2013

Definitions of Terms Used in Standard

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

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-~~2a~~3**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-~~2~~3, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-~~2a~~3:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.

- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past

studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the

use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
    a. Loss of a tower line with three or more circuits.[11]
    b. Loss of all Transmission lines on a common Right-of-Way[11].
    c. Loss of a switching station or substation (loss of one voltage level plus transformers).
    d. Loss of all generating units at a generating station.
    e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
    a. Loss of two generating stations resulting from conditions such as:
        i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
        ii. Loss of the use of a large body of water as the cooling source for generation.
        iii. Wildfires.
        iv. Severe weather, e.g., hurricanes, tornadoes, etc.
        v. A successful cyber attack.
        vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
    b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
    a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    e. 3Ø internal breaker fault.
    f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, &

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
   a. Date, time, and location for the meeting
   b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
   c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
   a. System Load level and estimated annual hours of exposure at or above that Load level
   b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
   a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do~~es~~ not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

~~In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW.~~

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do~~es~~ not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	03/17/2001	Revision of TPL-001-0 to modify only Table 1 footnote b. Approved by Board of Trustees	Project 2006-02 – revision to address FERC directive
2	To be Determined	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2a	February 2013	Address remand of proposed footnote 'b' pursuant to FERC Order RM06-16-009	Revised

Implementation Plan for TPL-001-3

Prerequisite Approvals

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

TPL-001-3 — Transmission System Planning Performance Requirements

In revising the TPL standards, the SDT is assuming that planners will receive valid data from the MOD standards link described in TPL-001-3, Requirement R1. Furthermore, there is a tacit assumption that future revisions of the MOD standards will include steps to validate MOD based data.

Revision to Sections of Approved Standards and Definitions

There are multiple new definitions in the proposed standard.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Compliance with Standards

Standard	Functions That Must Comply With the Associated Requirements	
	Transmission Planner	Planning Coordinator
TPL-001-3 — Transmission System Planning Performance Requirements	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-3:

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

TPL-001-1a, TPL-002-2b, TPL-003-1b, and TPL-004-1a are being retired as they are replaced in their entirety by TPL-001-3. TPL-005-0 and TPL-006-0.1 are being retired because their requirements are adequately covered by the revised TPL-001-3 and NERC's Rules of Procedure, Section 800. TPL-001-1a, TPL-002-2b, TPL-003-1b, TPL-004-1a, TPL-005-0 and TPL-006-0.1 are being retired on midnight of the day immediately prior to the Effective Date of TPL-001-3 in the particular jurisdictions in which TPL-001-3 is becoming effective. However, during this 24-month period, all aspects of TPL-001-1a through TPL-006-0.1 shall remain in effect for compliance monitoring. This 24 month period is to allow entities to develop, perform and/or validate new and/or modified studies, methodologies, assessments, procedures, etc. necessary to implement and meet the TPL-001-2a requirements. The specified effective dates are expected to allow sufficient time for proper assessment of the available options necessary to create a viable Corrective Action Plan that is compliant with the new Standard.

R1. This Requirement is related to maintaining System models and the data needed to do so. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

R7. This Requirement identifies an obligation to determine individual and joint responsibilities for performing studies needed to do the Planning Assessment. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes

into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

TPL-001-3 ‘raises the bar’ in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-1a, TPL-002-2b, TPL-003-1b and TPL-004-1a because loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by many to allow such actions. As shown in Table 1 of TPL-001-3, the performance requirements associated with the following events represent “raising the bar”:

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

This “raising the bar” is beyond the control of the Transmission Planner and Planning Coordinator and may have significant budget, siting, permitting, and construction impacts on many Transmission Owners. To provide stakeholders with sufficient time to implement changes, a timeframe coincident with the end of the Near-Term Transmission Planning Horizon has been provided

Any entity which cannot eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for these performance elements by that date shall submit a mitigation plan to its Regional Entity outlining the steps it will take to correct the problem. If the entities follow the established ERO procedure for mitigation, it is the intent of the SDT that no penalties will be assessed.

Implementation Plan for TPL-001-~~2a~~3

Prerequisite Approvals

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

TPL-001-~~2a~~ 3 — Transmission System Planning Performance Requirements

In revising the TPL standards, the SDT is assuming that planners will receive valid data from the MOD standards link described in TPL-001-~~2a~~3, Requirement R1. Furthermore, there is a tacit assumption that future revisions of the MOD standards will include steps to validate MOD based data.

Revision to Sections of Approved Standards and Definitions

There are multiple new definitions in the proposed standard.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Compliance with Standards

Standard	Functions That Must Comply With the Associated Requirements	
TPL-001-~~2a~~ 3 — Transmission System Planning Performance Requirements	Transmission Planner	Planning Coordinator
	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-~~2a~~3:

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

TPL-001-1a, TPL-002-~~1c~~2b, TPL-003-1b, and TPL-004-1a are being retired as they are replaced in their entirety by TPL-001-~~2a~~3. TPL-005-0 and TPL-006-0.1 are being retired because their requirements are adequately covered by the revised TPL-001-~~2a~~ 3 and NERC's Rules of Procedure, Section 800. TPL-001-1a, TPL-002-~~1c~~2b, TPL-003-1b, TPL-004-1a, TPL-005-0 and TPL-006-0.1 are being retired on midnight of the day immediately prior to the Effective Date of TPL-001-~~2a~~3 in the particular jurisdictions in which TPL-001-~~2a~~ 3 is becoming effective. However, during this 24-month period, all aspects of TPL-001-1a through TPL-006-0.1 shall remain in effect for compliance monitoring. This 24 month period is to allow entities to develop, perform and/or validate new and/or modified studies, methodologies, assessments, procedures, etc. necessary to implement and meet the TPL-001-2a requirements. The specified effective dates are expected to allow sufficient time for proper assessment of the available options necessary to create a viable Corrective Action Plan that is compliant with the new Standard.

R1. This Requirement is related to maintaining System models and the data needed to do so. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

R7. This Requirement identifies an obligation to determine individual and joint responsibilities for performing studies needed to do the Planning Assessment. This requirement shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this requirement goes into effect on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

TPL-001-~~2a~~ 3 'raises the bar' in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-1a, TPL-002-~~1c~~2b, TPL-003-1b and TPL-004-1a because loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by many to allow such actions. As shown in Table 1 of TPL-001-~~2a~~3, the performance requirements associated with the following events represent "raising the bar":

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

This "raising the bar" is beyond the control of the Transmission Planner and Planning Coordinator and may have significant budget, siting, permitting, and construction impacts on many Transmission Owners. To provide stakeholders with sufficient time to implement changes, a timeframe coincident with the end of the Near-Term Transmission Planning Horizon has been provided

Any entity which cannot eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for these performance elements by that date shall submit a mitigation plan to its Regional Entity outlining the steps it will take to correct the problem. If the entities follow the established ERO procedure for mitigation, it is the intent of the SDT that no penalties will be assessed.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan for Project 2010-11: TPL Table 1 Order

Prerequisite Approvals

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

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed standards.

Compliance with Standards

Standards	Functions That Must Comply With the Associated Requirements	
	Transmission Planner	Planning Authority
TPL-001-1: System Performance Under Normal (No Contingency) Conditions (Category A) TPL-002-2b: System Performance Following Loss of a Single Bulk Electric System Element (Category B) TPL-003-1: System Performance Following Loss of Two or More Bulk Electric System Elements (Category C) TPL-004-1: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)	X	X

Effective Dates

The effective date is the date entities are expected to meet the performance identified in this standard.

The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other

requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective.

All other requirements remain in effect as per previous approvals.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for Project 2010-11: TPL Table 1 Order

Prerequisite Approvals

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

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed standards.

Compliance with Standards

Standards	**Functions That Must Comply With the Associated Requirements**	
TPL-001-1: System Performance Under Normal (No Contingency) Conditions (Category A) TPL-002-~~1c~~2b: System Performance Following Loss of a Single Bulk Electric System Element (Category B) TPL-003-1: System Performance Following Loss of Two or More Bulk Electric System Elements (Category C) TPL-004-1: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)	Transmission Planner	Planning Authority
	X	X

Effective Dates

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Implementation Plan for Project 2010-11: TPL Table 1 Order

Prerequisite Approvals

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

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed standards.

Compliance with Standards

Standards	Functions That Must Comply With the Associated Requirements	
	Transmission Planner	Planning Authority
TPL-001-1: System Performance Under Normal (No Contingency) Conditions (Category A) TPL-002-2b: System Performance Following Loss of a Single Bulk Electric System Element (Category B) TPL-003-1: System Performance Following Loss of Two or More Bulk Electric System Elements (Category C) TPL-004-1: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)	X	X

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Implementation Plan for Project 2010-11: TPL Table 1 Order

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Standards	Functions That Must Comply With the Associated Requirements	
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All other requirements remain in effect as per previous approvals.

Standards Announcement

Project 2010-11– TPL Table 1 Order
TPL-002-2b, footnote ‘b’ and TPL-001-3, footnote 12

Recirculation Ballot is now open through 8 p.m. Thursday, January 31, 2013

Now Available

A recirculation ballot is now open for revisions to a single footnote that is incorporated into two standards (**TPL-002-2b**– System Performance Following Loss of a Single BES Element for footnote ‘b’, and **TPL-001-3** – Transmission System Planning Performance Requirements for footnote 12) through **8 p.m. Eastern Thursday, January, 31, 2013**.

IMPORTANT NOTICE (PLEASE READ): This recirculation ballot includes a substantive change to TPL-002-2b (formerly referred to as TPL-002-1c), footnote b and TPL-001-3 (formerly referred to as TPL-001-2a), footnote 12 to address applicability to registered entities in Canada and Mexico. The change adds text to the footnotes and Attachment 1 that addresses jurisdictional differences – specifically, that the 75 MW limit on planned, non-consequential load loss included in the footnotes and Attachment would not apply to Canadian or Mexican registered entities. The inclusion of this substantive change during a recirculation ballot was approved by the Standards Committee as a deviation from the Standard Processes Manual to provide NERC with an opportunity to meet a February 2013 deadline from the Federal Energy Regulatory Commission.

Please also note that NERC has identified that the drafting team was given incorrect guidance on the proper numbering of the standards to account for the revision to be consistent with the NERC Standards Numbering Convention**. The standards versions have been updated to reflect the appropriate numbering convention and are now identified as TPL-002-2b and TPL-001-3.**

Instructions

In the recirculation ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the recirculation ballot window. If a ballot pool member does not participate in the recirculation ballot, that member’s vote cast in the previous ballot will be carried over as that member’s vote in the recirculation ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the footnote by clicking here.

Next Steps

Voting results will be posted and announced after the ballot window closes. If approved, the footnote will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background

FERC Order No. 762, issued April 19, 2012, remanded TPL-002-0b to NERC as vague, unenforceable and not responsive to the previous Commission directives on this matter. The Standards Committee directed the Standards Drafting Team (SDT) to revise footnote 'b' in accordance with the directives of Orders No. 693 and 762. The SDT was also charged with revising the corresponding footnote 12 of TPL-001-2 in order to prevent the remand of TPL-001-2.

In revising the footnotes, the SDT adopted a philosophy of minimal changes to the actual footnote itself. This was done to minimize confusion as to what was changed, for ease of reading and following the footnote, and for formatting within the actual standards documents. Instead, the SDT revised the footnote by developing an attachment to the footnote containing changes in response to the Commission orders. It should be noted that attachments to standards are an extension of the Requirements and thus are binding to applicable entities.

Project 2010-11 is an important part of the ERO's strategic goal to be responsive to regulatory authority directives in an expeditious manner in order to reduce the amount of standards-related directives and to provide an adequate level of reliability.

Additional information can be found on the project page.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process, including the appeals process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Development Administrator, at monica.benson@nerc.net or at 404-446-2560.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2010-11– TPL Table 1 Order
TPL-002-2b, footnote ‘b’ and TPL-001-3, footnote 12

Recirculation Ballot Results

Now Available

A recirculation ballot for revisions to a single footnote that is incorporated into two standards (**TPL-002-2b**– System Performance Following Loss of a Single BES Element for footnote ‘b’, and **TPL-001-3** – Transmission System Planning Performance Requirements for footnote 12) concluded at **8 p.m. Eastern on Thursday, January, 31, 2013**.

Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results.

Approval
Quorum: 88.55% Approval: 69.63%

Next Steps

The footnote will be presented to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background

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In revising the footnotes, the SDT adopted a philosophy of minimal changes to the actual footnote itself. This was done to minimize confusion as to what was changed, for ease of reading and following the footnote, and for formatting within the actual standards documents. Instead, the SDT revised the footnote by developing an attachment to the footnote containing changes in response to the Commission orders. It should be noted that attachments to standards are an extension of the Requirements and thus are binding to applicable entities.

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Ballot Results	
Ballot Name:	Project 2010-11 Recirculation Ballot Jan 2013_in
Ballot Period:	1/22/2013 - 1/31/2013
Ballot Type:	Recirculation
Total # Votes:	317
Total Ballot Pool:	358
Quorum:	**88.55 % The Quorum has been reached**
Weighted Segment Vote:	69.63 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	102	1	57	0.814	13	0.186	21	11
2 - Segment 2.	10	0.9	6	0.6	3	0.3	0	1
3 - Segment 3.	82	1	42	0.724	16	0.276	15	9
4 - Segment 4.	25	1	11	0.786	3	0.214	8	3
5 - Segment 5.	73	1	30	0.732	11	0.268	20	12
6 - Segment 6.	48	1	23	0.657	12	0.343	11	2
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.5	2	0.2	3	0.3	0	3
9 - Segment 9.	3	0.2	0	0	2	0.2	1	0
10 - Segment 10.	7	0.6	5	0.5	1	0.1	1	0
Totals	**358**	**7.2**	**176**	**5.013**	**64**	**2.187**	**77**	**41**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1		Vijay Sankar		
1	Ameren Services	Kirit Shah	Abstain	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Abstain	

1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Abstain	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	
1	Corporate Risk Solutions, Inc.	Joseph Doetzl	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker	Abstain	
1	Dominion Virginia Power	Michael S Crowley		
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Negative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	FortisBC	Curtis Klashinsky		
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JEA	Ted Hobson		
1	KAMO Electric Cooperative	Walter Kenyon		
1	Keys Energy Services	Stanley T Rzad	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Abstain	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Negative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Negative	
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins	Negative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	

1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Abstain	
1	Seattle City Light	Pawel Krupa	Abstain	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Mississippi Electric Power Association	Rodney A. Wilson		
1	Southern California Edison Company	Steven Mavis	Abstain	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young	Affirmative	
1	Tennessee Valley Authority	Howell D Scott	Negative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Negative	
2	Midwest ISO, Inc.	Marie Knox	Negative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Negative	
3	Ameren Services	Mark Peters	Abstain	
3	APS	Steven Norris	Negative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Robert Lafferty		
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Homestead	Orestes J Garcia	Affirmative	
3	City of Redding	Bill Hughes	Abstain	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Abstain	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	
3	Consumers Energy	Richard Blumenstock	Abstain	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr		

3	Entergy	Joel T Plessinger	Negative	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey	Negative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Abstain	
3	Mississippi Power	Jeff Franklin	Negative	
3	Modesto Irrigation District	Jack W Savage	Negative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Abstain	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Abstain	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Gary Clear		
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Negative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	Snohomish County PUD No. 1	Mark Oens	Abstain	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Negative	
4	American Municipal Power	Kevin Koloini		
4	Arkansas Electric Cooperative Corporation	Ronnie Frizzell		
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Abstain	
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	

4	Consumers Energy	David Frank Ronk	Abstain	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	
4	South Mississippi Electric Power Association	Steven McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Negative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Abstain	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Jennifer Eckels	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	
5	Consumers Energy Company	David C Greyerbiehl	Abstain	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Electric Power Supply Association	John R Cashin		
5	Energy Services, Inc.	Tracey Stubbs		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Abstain	
5	MidAmerican Energy Co.	Neil D Hammer	Abstain	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		

5	Platte River Power Authority	Roland Thiel	Negative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Abstain	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	Southern California Edison Company	Denise Yaffe	Negative	
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Xcel Energy, Inc.	Liam Noailles	Negative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	APS	Randy A. Young	Negative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Abstain	
6	Cleco Power LLC	Robert Hirchak		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Negative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	Modesto Irrigation District	James McFall	Negative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Abstain	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Kelly Cumiskey	Abstain	
6	Platte River Power Authority	Carol Ballantine	Negative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	Kenn Backholm	Abstain	
6	South Mississippi Electric Power Association	Joel Rogers		
6	Southern California Edison Company	Lujuanna Medina	Negative	

6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	
8		Edward C Stein		
8		Roger C Zaklukiewicz		
8	JDRJC Associates	Jim Cyrulewski	Negative	
8	Massachusetts Attorney General	Frederick R Plett	Negative	
8	Transmission Strategies, LLC	Bernie M Pasternack	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Abstain	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Negative	
9	New York State Department of Public Service	Thomas G. Dvorsky	Negative	
10	Midwest Reliability Organization	William S Smith	Affirmative	
10	New York State Reliability Council	Alan Adamson	Negative	
10	Northeast Power Coordinating Council	Guy V. Zito	Abstain	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Account Log-In/Register

Exhibit J

Standard Drafting Team Roster for NERC Standards Development Project 2011-10

Project 2010-11 TPL Table 1

Name and Title	Company and Address	Contact Info	Bio
John Odom, Chair Vice President of Planning and Operations	Florida Reliability Coordinating Council, Inc. 1408 N. Westshore Blvd., Suite 1002 Tampa, FL 33607-4512	(813)207-7985 jodom@ frcc.com	John Odom is Vice President of Planning and Operations at the Florida Reliability Coordinating Council (FRCC). John joined FRCC in May, 2005 after 26 years at Progress Energy Corporation (PEF). He is responsible for oversight of all Member Services Activities, including the FRCC standing committees, FRCC Reliability Coordinator, and Planning Authority function. Additionally, he oversees the Regional Entity functions of reliability assessment, situational awareness, training, certification of system operators, and event analysis. From 2001 – 2007, John was the FRCC Representative on the NERC Reliability Assessment Subcommittee (RAS). John is currently the chair of the Assess Future Transmission Needs Standards Drafting Team (AFTNSDT), which is re-writing the existing TPL-001 through TPL-006.
Douglas Hohlbaugh, Vice Chair Standards Development Manager	FirstEnergy Corp. 76 South Main Street 10th Floor Akron, Ohio 44308	(330) 384-4698 hohlbaughdg@ firstenergycorp. com	Doug Hohlbaugh holds a Bachelor of Science in Electrical Engineering from Akron University (1989) and a Professional Engineering license in the state of Ohio. His 20 plus years experience in the electric utility industry has involved the transmission business of FirstEnergy with a focus on transmission planning. His work experience includes various technical positions in transmission and distribution, as well as sales and marketing experience with FirstEnergy's (FE) unregulated energy services Existing responsibilities include the Reliability Standards Development Lead of the FirstEnergy FERC Compliance Department including oversight of newly proposed and/or revised reliability standards governing the bulk electric transmission system. The responsibilities include overseeing and ensuring timely implementation of all new reliability standard development projects at both the North American Electric Reliability Corporation (NERC) and Reliability First Corporation (RFC) having impact on a variety of FE business units which support the reliable operation of the bulk transmission system.
D. Darrin Church Principal Engineer Bulk Transmission Planning	Tennessee Valley Authority 1101 Market Street MR 5G-C Chattanooga, Tennessee 37402-2801	423) 751-6899 (423) 751-3453 Fx ddchurch@tva. gov	Darrin Church is a Principal Bulk Planning Engineer in TVA's Transmission Planning Department. Darrin has 15 years experience in Bulk Transmission Planning along with 5 years previous experience in planning relaying and protection schemes. Responsibilities include insuring reliability of TVA's 500 kV, 230 kV, 161 kV, and 115 kV transmission systems which include initiating capital projects required to maintain an adequate and reliable transmission system per NERC Reliability Standards.

William Harm Senior Consultant	PJM Interconnection, L.L.C. 955 Jefferson Ave Valley Forge Corporate Center Norristown, Pennsylvania 19403-2497	(610) 666-8868 harm@pjm.com	Bill Harm has over 35 years of industry experience with PJM through various assignments involving real time operation, operations planning, and transmission planning. Mr. Harm's current responsibilities involve performance assessment and policy development responsibilities. He either has or continues to represent PJM in various industry forums and groups, including RFC, NERC, and the ISO/RTO forums. He earned a Bachelor and Maters of Science Degree in Electrical Engineering from Drexel University and is a registered professional Engineer in the Commonwealth of PA.
Julius Horvath Manager Planning & Operations	Wind Energy Transmission Texas, LLC	(512)496-9186 julius.horvath@windenergyoftexas.com	Julius Horvath is currently the Planning and Operations Manager at Wind Energy Transmission Texas, LLC (WETT), in Austin, Texas. Julius has over 12 years of utility experience at the Bonneville Power Administration, Wind Energy Transmission Texas, LLC, Lonestar Transmission, LLC and the Lower Colorado River Authority in Transmission Planning. Julius is a Registered Profession Engineer in the State of Texas.
Robert A. Jones Project Manager, Stability Studies	Southern Company Services P.O. Box 2641 Birmingham, Alabama 35291	(205) 257-6148 rajones@southernco.com	Robert Jones obtained a BSEE degree from the University of Alabama in 1973 and a MSEE degree from University of Alabama – Birmingham in 1978. He has worked for 37 years for Southern Company Services. Eighteen of those years have been in Transmission Planning. The last 15 years, he has been responsible for stability studies for Southern Company.
Brian K. Keel Manager, Transmission System Planning	Salt River Project MS POB100 PO Box 52025 Phoenix, Arizona 85072	602-236-0970 brian.keel@srpnet.com	Brian Keel has a Bachelor and Master Degrees in Electrical Engineering, specializing in power systems, from the University of Illinois. Brian was employed by Duke Power for over one year and PSI Energy for 8 years. Brian has been at SRP since 1998 and is currently the Manager of Transmission System Planning. Brian has Chaired four groups within WECC mainly concentrating on transmission reliability. Brian is a current member of the NERC TADS Work Group.
R. W. Mazur Manager System Planning Department	Manitoba Hydro 12-1146 Waverly Street P.O. Box 815 Winnipeg, Manitoba R3C 2P4	(204) 474-3113 rwmazur@hydro.mb.ca	Ronald W. Mazur obtained his Bachelor of Science in Electrical Engineering degree in 1971, and his Masters of Science in Electrical Engineering degree in 1989, both from the University of Manitoba. Ron Mazur is a registered professional engineer with the Association of Professional Engineers and Geoscientists of Manitoba. Ron joined Manitoba Hydro in 1974, where he worked in station design for 5 years, and in system performance (operations) for 6 years, and in system planning since 1986. He is currently the Manager of the System Planning Department responsible for the expansion planning of Manitoba Hydro's transmission system (100 kV and above) and the HVDC system. Ron is a Canadian representative on the NERC Planning Committee, and Chair of the Planning Committee of the Midwest Reliability Organization.
Thomas C. Mielnik Manager Electric System Planning	MidAmerican Energy Co. 106 East Second Street Davenport, Iowa 52808	(563) 333-8129 tcmielnik@midamerican.com	Thomas Mielnik has over 37 years experience in Electric Utility Planning. He has been the Manager of Electric System Planning for MEC from 1995 to the present. He was a member of the NERC ATC Working Group from 1996 to 1999 and is a Registered Professional Engineer.

Bernie M Pasternack, President, P.E.	Transmission Strategies 4347 Harborough Rd Upper Arlington, Ohio 43220	(614) 459-5806 bmpasternack@ att.net	Bernie Pasternack was employed by the AEP Service Corporation for over 41 years, where he spent his entire career in various aspects of transmission planning and asset management. After retiring from AEP in June 2010, he formed his own consulting practice, providing services to the electric utility industry. He holds BEE and MSEE degrees from Rensselaer Polytechnic Institute and an MBA from Fairleigh Dickinson University. Before retiring from AEP, Bernie was responsible for the planning and management of AEP's transmission assets. His department provided the analytical and planning services for the entire AEP System, eleven operating companies, and a transmission network consisting of transmission facilities ranging in voltage from 23 kV to 765 kV. This system spans eleven states and three reliabilty regions (RFC, SPP, and ERCOT). Bernie was also responsible for providing input to policy making decisions relative to AEP's transmission strategy and business plan. Bernie directed the analytical and planning services provided to the eleven operating companies. Such services included future system performance appraisal and planning studies, IPP interconnection studies, and all analytical studies dealing with the steady-state and dynamic operation of interconnected power systems. Based on an evaluation of the results of these studies, the Transmission Planning group developed and recommended capital improvement projects and programs for the reinforcement of the AEP System transmission network. In parallel with these efforts, the Transmission Asset Engineering group developed capital rehabilitation programs and set maintenance guidelines to maintain the health of AEP's transmission assests. During his career, Bernie has made significant contributions to a variety of industry organizations including IEEE, CIGRE, EPRI, EEI, ECAR/RFC, and NERC. He was a member of the EEI Transmission Policy TF and AEP's representative on the Reliability First Corporation Reliability Committee. Bernie has also played an active role in many NERC activities over the past twenty years, including its Planning Committee and a number of its subcommittees, working groups, and standards drafting teams.
Bob Pierce Senior Engineer	Duke Energy 526 South Church Street MC EC10Q Charlotte, North Carolina 28201-1006	(980) 373-6480 bob.pierce@ duke- energy.com	Robert (Bob) Pierce is a Consulting Engineer at Duke Energy where he specializes in Bulk System Planning, NERC standards, and FERC regulations. He holds a B.S. in Nuclear Engineering from Pennsylvania State University and a M.S. in Electrical Engineering from the University of North Carolina-Charlotte. Mr. Pierce is a registered Professional Engineer with 13 years Transmission Planning experience and a total of 31 years of power system experience.

Dana Walters Director of Reliability and Economic Planning	NYISO 10 Krey Blvd., Rensselaer, NY 12144	518-356-8582 DWalters@NYISO.com	Dana Walters is currently Director of Reliability and Economic Planning at the NYISO. However, at the time of the work effort he was a Manager in the Transmission Planning group at National Grid. Mr. Walters has 36 year of experience in the Electric Utility industry. Most of his experience involves various aspects of Transmission Planning. This includes topics such as analytical studies of thermal, stability, short circuit, generator interconnections, and lightning protection. Other areas of experience include involvement in investment planning, tariff design, consulting, production cost analysis, and distribution planning. In his role as a Transmission Planner, Mr. Walters has been involved in numerous committees and working groups at the NERC, NPCC, and ISO levels. Mr. Walters has a Masters in Engineering Management from Northeastern University and a Bachelor in Electrical Engineering with a focus in Power Systems also from Northeastern University. Mr. Walters is a registered professional engineer in New Hampshire and is a member of IEEE.