NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

May 4, 2012

VIA ELECTRONIC FILING

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

Re: ***North American Electric Reliability Corporation***
Docket No. RR12-___-000

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits this petition in accordance with Section 215(d) (1) of the Federal Power Act ("FPA") and Part 39.5 of the Federal Energy Regulatory Commission's ("FERC") regulations seeking approval of proposed Regional Reliability Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding, associated Violation Risk Factors ("VRF") and Violations Severity Levels ("VSL"), and an implementation plan for PRC-006-NPCC-1. Upon approval, this standard will only be effective within the Northeast Power Coordinating Council ("NPCC") footprint.

The purpose of PRC-006-NPCC-1 is to provide a Regional Reliability Standard that ensures the development of an effective automatic underfrequency load shedding ("UFLS") program in order to preserve the security and integrity of the bulk power system during declining system frequency events, in coordination with the NERC UFLS reliability standard characteristics, PRC-006-1.

The proposed Regional Reliability Standard was approved by the NERC Board of Trustees during its February 9, 2012 meeting. NERC is proposing dual effective dates for the standard. NERC proposes that for the Eastern Interconnection and Québec Interconnection portions of NPCC excluding the Independent Electricity System Operator ("IESO") Planning Coordinator area of NPCC in Ontario, Canada:

> The effective date for Requirements R1, R2, R3, R4, R5, R6, and R7 is the first day of the first calendar quarter following applicable regulatory approval but no earlier than January 1, 2016. The effective date for Requirements R8 through R23 is the first day of the first calendar quarter two years following applicable governmental and regulatory approval.

For the Commission's information, NERC is proposing the following for the IESO Planning Coordinator's area of NPCC in Ontario, Canada:

> All requirements are effective the first day of the first calendar quarter following applicable governmental and regulatory approval but no earlier than April 1, 2017.

This petition consists of the following:

- this transmittal letter;
- a table of contents for the entire petition;
- a narrative description explaining how the proposed Regional Reliability Standard meets FERC's requirements;
- Regional Reliability Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding and implementation plan, submitted for approval (**Exhibit A**);
- the complete development record of the proposed Regional Reliability Standard (**Exhibit B**);
- the standard drafting team roster (**Exhibit C**); and
- the Violation Severity Level and Violation Risk Factor Guideline Analysis (**Exhibit D**).

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Andrew M. Dressel
Andrew M. Dressel
Attorney for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**) Docket No. RR12-__-000** **)**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED NPCC REGIONAL RELIABILITY STANDARD PRC-006-NPCC-1 — AUTOMATIC UNDERFREQUENCY LOAD SHEDDING

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I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[1] hereby requests the Federal Energy Regulatory Commission ("FERC") to approve, in accordance with Section 215(d)(1) of the Federal Power Act ("FPA")[2] and Section 39.5 of FERC's regulations, 18 C.F.R. § 39.5, proposed Regional Reliability Standard, PRC-006-NPCC-1 included in Exhibit A.

The purpose of PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding is to provide a Regional Reliability Standard that ensures the development of an effective automatic underfrequency load shedding ("UFLS") program in order to preserve the security and integrity of the bulk power system during declining system frequency events, in coordination with the NERC UFLS Reliability Standard characteristics. UFLS requirements have been in place at a continent-wide level and within Northeast Power Coordinating Council, Inc. ("NPCC") for many years prior to implementation of federally-mandated reliability standards in 2007.

NERC and NPCC believe that a region-wide and fully coordinated single set of UFLS requirements is of benefit to achieving an effective and efficient UFLS program, and their experience has supported that belief. Regional UFLS programs serve "as a last resort to preserve the Bulk-Power System during a major system failure that could cause system frequency to collapse."[3] The NPCC standard adds specificity not contained in the NERC standard for development and implementation of a UFLS program in the NPCC

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[1] NERC has been certified by FERC as the Electric Reliability Organization ("ERO") authorized by Section 215 of the Federal Power Act. FERC certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000. 116 FERC ¶ 61,062 (2006) ("ERO Certification Order).

[2] 16 U.S.C. 824o.

[3] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1476, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

region that effectively arrests declining frequency, assists recovery following underfrequency events, and provides last resort system preservation measures.

This petition is the first request by NERC for FERC approval of this proposed Regional Reliability Standard. The Regional Reliability Standard proposed will be in effect only for applicable registered entities within the NPCC. NERC continent-wide Reliability Standards do not presently address all of the issues covered in this proposed Regional Reliability Standard.

NERC specifically requests approval of:

- Regional Reliability Standard PRC-006-NPCC-1;
- Associated Violations Risk Factors (“VRF”) and Violation Severity Levels (“VSL”); and
- Implementation Plan for PRC-006-NPCC-1.

On February 9, 2012 the NERC Board of Trustees approved PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding. NERC requests that FERC approve this Regional Reliability Standard and make it effective upon FERC approval for the section of the NPCC region that lies within the United States, consistent with the proposed implementation plan. **Exhibit A** to this filing sets forth the proposed Regional Reliability Standard and implementation plan. **Exhibit B** contains the complete Development Record for the proposed Regional Reliability Standard. **Exhibit C** includes the standard drafting team roster. **Exhibit D** is the Violation Severity Level (“VSL”) and Violation Risk Factor (“VRF”) guideline analysis.

NERC is also filing the proposed PRC-006-NPCC-1 Regional Reliability Standard and associated documents with the applicable governmental authorities in Canada.

II. NOTICES AND COMMUNICATIONS

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

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III. BACKGROUND

a. Regulatory Framework

By enacting the Energy Policy Act of 2005,[4] Congress entrusted FERC 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 FERC 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 FERC-approved Reliability Standards.

b. Basis for Approval of Proposed Regional Reliability Standard

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

> FERC may approve, by rule or order, a proposed reliability standard or modification to a reliability standard if it determines that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[5]

When evaluating proposed Reliability Standards, FERC is expected to give "due weight" to the technical expertise of the ERO and to the technical expertise of a Regional Entity organized on an Interconnection-wide basis with respect to a Reliability Standard

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[4] 16 U.S.C. § 824o.
[5] 16 U.S.C. § 824o(d)(2).

to be applicable within that Interconnection. Order No. 672 provides guidance on the factors FERC will consider when determining whether proposed Reliability Standards meet the statutory criteria.[6]

A Regional Reliability Standard proposed by a Regional Entity must meet the same standards that NERC's Reliability Standards must meet, *i.e.*, the Regional Reliability Standard must be shown to be just, reasonable, not unduly discriminatory or preferential, and in the public interest.[7] FERC's Order No. 672 also requires additional criteria that a Regional Reliability Standard must satisfy: a regional difference from a continent-wide Reliability Standard must either be (1) more stringent than the continent-wide Reliability Standard (which includes a regional standard that addresses matters that the continent-wide Reliability Standard does not), or (2) a Regional Reliability Standard that is necessitated by a physical difference in the Bulk Power System.[8]

NPCC is not an "interconnection-wide" Regional Entity and its standards are intended to apply only to that part of the Eastern Interconnection within the NPCC geographical footprint and Québec. As discussed in the *Northeast Power Coordinating Council, Inc. Regional Reliability Standard Development Procedure,*[9] NPCC's standards are developed according to the following characteristic attributes:

- **Open —** The NPCC Regional Reliability Standards Development Procedure provides any person the ability to participate in the development of a standard. Any entity that is directly and materially affected by the reliability of the NPCC's Bulk Power System has the ability to participate in the

[6] *See Rules Concerning Certification of the Electric Reliability Organization; Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards, FERC Stats. & Regs.*, ¶ 31,204 at PP 320-338 ("Order No. 672"), *order on reh'g*, FERC Stats. & Regs. ¶ 31,212 (2006) ("Order No. 672-A").

[7] Section 215(d)(2) of the FPA and 18 C.F.R. §39.5(a).

[8] Order No. 672 at P 291.

[9] The *Northeast Power Coordinating Council, Inc. Regional Reliability Standard Development Procedure* is available at http://www.npcc.org/regStandards/Overview.aspx

development and approval of reliability standards. There are no undue financial barriers to participation. Participation in the open comment process is not conditional upon membership in the ERO, NPCC or any organization, and participation is not unreasonably restricted on the basis of technical qualifications or other such requirements. NPCC utilizes a website to accomplish this. Online posting and review of standards and the real time sharing of comments uploaded to the website allow complete transparency.

- **Inclusive —** The NPCC Regional Reliability Standards Development Procedure provides any person with a direct and material interest the right to participate by expressing an opinion and its basis, have that position considered, and appealed through an established appeals process if adversely affected.
- **Balanced —** The NPCC Regional Reliability Standards Development Procedure has a balance of interests and all those entities that are directly and materially affected by the reliability of the NPCC's Bulk Power System are welcome to participate and shall not be dominated by any two interest categories and no single interest category shall be able to defeat a matter. This will be accomplished through the NPCC Bylaws defining eight sectors (categories) for voting.
- **Fair Due Process —** The NPCC Regional Reliability Standards Development Procedure provides for reasonable notice and opportunity for public comment. The procedure includes public notice of the intent to develop a standard, a 45 calendar day public comment period on the proposed standard request, or standard with due consideration of those public comments, and responses to those comments will be posted on the NPCC website. A final draft will be posted for a 30 calendar day pre-balloting period, and then a ballot of NPCC Members will be conducted. Upon approval by the NPCC Members, the NPCC Board then votes to approve submittal of the Regional Standard to NERC.
- **Transparent —** All actions material to the development of Regional Reliability Standards are transparent and information regarding the progress is posted on the NPCC website as well as through extensive email lists.

Proposed NPCC standards are subject to approval by NERC, as the ERO, and FERC before becoming mandatory and enforceable under Section 215 of the FPA.[10] As shown above, the NPCC Regional Reliability Standard was developed in an open, transparent, and inclusive fashion. During development of the standard, workshops were conducted jointly with other Regional Entities and NPCC members. The proposed standard is

[10] 16 U.S.C. 824o.

widely supported by the NPCC ballot body and regulatory agencies that see this as a meaningful and necessary step forward in solving a longstanding problem. The standard was reviewed by NPCC legal counsel for consistency with the provisions and stated goals of the Federal Power Act and Chapter 39 of FERC's regulations.[11] As a condition of NPCC membership, all NPCC Members[12] agree to adhere to the NERC Reliability Standards in addition to the NPCC Regional Reliability Standards. NERC Reliability Standards and the NPCC Regional Reliability Standards are both enforced through the NPCC Compliance Program.

The NPCC drafting team worked closely with its technical committee on UFLS, the SS-38 Working Group on Inter-Area Dynamics Analysis, as it considered the technical issues and justifications surrounding the standard.

Additionally, NPCC conducted a number of regional workshops aimed at informing NPCC Members on the status and background of the standard's development. The draft of the standard was posted for a 45 day comment period three times during its development and the drafting team responded to all comments and technical concerns that were raised.

NERC conducted two quality reviews of the standard during which formatting and content issues were corrected. NERC also posted the draft for public consideration on two occasions after which the drafting team responded to all comments received.

As previously noted, NPCC is a Regional Entity not organized on an Interconnection-wide basis. Therefore, NERC is not required to rebuttably presume the

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[11] 18 C.F.R. §39 (2011).
[12] As defined in Section IV.B of the NPCC Corporation By-laws. Available at: http://www.npcc.org/documents/aboutus/BusPlanBylaws.aspx.

proposed standard is just, reasonable, not unduly discriminatory or preferential and in the public interest.

IV. JUSTIFICATION FOR APPROVAL OF PROPOSED REGIONAL RELIABILITY STANDARD

This section summarizes the development of the proposed Regional Reliability Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding; describes the reliability objectives to be achieved by the Regional Reliability Standard; explains the development history of the Regional Reliability Standard; and demonstrates how the standard meets the Commission's criteria for approval. NERC, in its analysis and approval of the proposed Regional Reliability Standard, determined that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

The complete development record for the proposed Regional Reliability Standard is provided in **Exhibit C** and includes the development and approval process, comments received during the industry-wide comment period, responses to those comments, ballot information, and NERC's evaluation of the proposed standard.

a. Basis and Purpose of Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding

The proposed Regional Reliability standard, PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding, will provide regional requirements for Automatic Underfrequency Load Shedding to applicable entities in NPCC. UFLS requirements have been in place at a continent-wide level and within NPCC for many years prior to the implementation of federally mandated reliability standards in 2007. NPCC and its members believe that a region-wide, fully coordinated single set of UFLS requirements is necessary to create an effective and efficient UFLS program, and their experience has supported that belief.

The proposed standard contains 23 requirements that establish UFLS obligations for entities within the NPCC region. The proposed standard is included in **Exhibit A** to this filing.

b. Order No. 672 Criteria

In Order No. 672, the Commission identified the criteria it will use to analyze Reliability Standards proposed for approval to ensure such standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standards have met or exceeded the criteria.

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal

> Order No. 672 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.

The proposed Regional Reliability Standard, PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding, was developed to provide a Regional Reliability Standard that ensures the development of an effective UFLS program that preserves the security and integrity of the bulk power system during declining system frequency events in coordination with the continent-wide PRC-006-1 Reliability Standard's requirements.

2. Proposed Reliability Standards must be applicable to users, owners, and operators of the bulk power system, and not others.

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

The proposed Regional Reliability Standard is only applicable to Generator Owners, Planning Coordinators, Distribution Providers, and Transmission Owners within the NPCC region. These entities are users, owners, or operators of the bulk power system.

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

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

All comments and concerns were addressed using the *Northeast Power Coordinating Council Standards Development Procedure* which is consensus-based, technically sound, and open to the public and bordering entities that may be impacted by a Regional Reliability Standard. No other factors were identified as necessary for consideration by the standard drafting team in the development of the proposed Regional Reliability Standard.

4. Proposed Reliability Standards must contain a technically sound method to achieve the goal.

> Order No. 672 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.

The proposed Regional Reliability Standard contains a technically sound means to achieve this goal. The PRC-006-NPCC-1 drafting team was comprised of power system engineers with experience in power system protection system design, power system operations, transmission, and generation. The proposed Regional Reliability Standard used as its basis the program characteristics defined within NPCC Directory #12 Underfrequency Load Shedding Program Requirements,[13] which contains the criteria that govern the NPCC Automatic UFLS program as designed by the NPCC Working Group on Inter-Area Dynamic Analysis (SS-38) and was approved by NPCC's highest level technical committee, the Reliability Coordinating Committee (RCC).

The proposed Regional Reliability Standard PRC-006-NPCC-1 was posted for industry technical comment three times and responses to these comments were evaluated and incorporated by the drafting team into the standard as appropriate.

5. Proposed Reliability Standards must be clear and unambiguous as to what is required and who is required to comply.

> Order No. 672 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.

The proposed Regional Reliability Standard establishes clear and unambiguous requirements for Generator Owners, Planning Coordinators, Distribution Providers, and Transmission Owners within the NPCC region as detailed below.

[13] NPCC Regional Reliability Reference Directory # 12 Underfrequency Load Shedding Program Requirements (2009) ("NPCC Directory # 12"). Available at http://www.theimo.com/imoweb/pubs/ircp/NPCC/Directory_12.pdf.

Requirement R1 requires each Planning Coordinator within the NPCC region to establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding as required by the islanding criteria requirements of the NERC continent-wide Standard PRC-006-1.

Requirement R2 requires each Planning Coordinator to identify to NPCC the generation facilities within its Planning Coordinator Area necessary to support the UFLS program performance characteristics within 30 days of completion of its system studies required by the NERC continent-wide Standard PRC-006-1.

Requirement R3 requires each Planning Coordinator to provide to the Transmission Owner, Distribution Provider, and Generator Owner within 30 days upon written request the requirements for entities aggregating the UFLS programs and requirements for compensatory load shedding program derived from each Planning Coordinator's system studies as determined by Requirement R1.

Requirement R4 requires each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC to implement an automatic UFLS program reflecting normal operating conditions excluding outages for its Facilities based on frequency thresholds, total nominal operating time and amounts specified in PRC-006-NPCC-1 Attachment C, Tables 1 through 3, or to collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1 and acting as a single entity, provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load, based on frequency thresholds, total nominal operating time and amounts specified in PRC-006-NPCC-1 Attachment C, Tables 1 through 3.

Requirement R5 requires each Distribution Provider or Transmission Owner that must arm its load to trip on underfrequency in order to meet its requirements as specified and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4 to:

5.1 Inform its Planning Coordinator of the need to exceed the stated tolerances or the number of stages as shown in PRC-006-NPCC-1 Attachment C, Table 1 if applicable and

5.2 Provide its Planning Coordinator with a technical study that demonstrates that the Distribution Providers or Transmission Owners specific deviations from the requirements of PRC-006-NPCC-1 Attachment C, Table 1 will not have a significant adverse impact on the bulk power system.

5.3 Inform its Planning Coordinator of the need to exceed the stated tolerances of PRC-006-NPCC-1 Attachment C, Table 2 or Table 3, and in the case of PRC-006-NPCC-1 Attachment C, Table 2 only, the need to deviate from providing two stages of UFLS, if applicable, and

5.4 Provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with PRC-006-NPCC-1 Attachment C Table 2 or PRC-006-NPCC-1 Attachment C Table 3.

Requirement R6 requires each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC to implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in PRC-006-NPCC-1 Attachment C, Table 4 or to collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in PRC-006-NPCC-1 Attachment C, Table 4.

Requirement R7 requires each Distribution Provider and Transmission Owner to set each underfrequency relay that is part of its region's UFLS program with a minimum time delay of 100 ms in the Eastern Interconnection and 200 ms in the Quebec Interconnection.

Requirement R8 requires each Planning Coordinator to develop and review once per calendar year settings for the inhibit thresholds to be utilized within its region's UFLS program.

Requirement R9 requires each Planning Coordinator to provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 days of the initial determination of those inhibit thresholds and within 30 days of any changes to those thresholds.

Requirement R10 requires each Distribution Provider and Transmission Owner to implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R9.

Requirement R11 requires each Distribution Provider and Transmission Owner to develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R9.

Requirement R12 requires each Transmission Owner and Distribution Provider to annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage coincident with their integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would be opened by the UFLS relays.

Requirement R13 requires each Generator Owner to set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in PRC-006-NPCC-1 Figure 1, except as otherwise exempted in Requirements R16 and R19.

Requirement R14 requires each Generator Owner to transmit the generator underfrequency trip setting and time delay to its Planning Coordinator within 45 days of the Planning Coordinator's request.

Requirement R15 requires each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard, or an existing generator increasing its net capability by greater than 10% to:

15.1 Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in PRC-006-NPCC-1 Figure 1.

15.2 Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in PRC-006-NPCC-1 Figure 1.

Requirement R16 requires each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in PRC-006-NPCC-1 Figure 1 to:

16.1 Set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

16.2 Transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

16.3 Have compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of their generator due to early tripping.

Requirement R17 requires each Planning Coordinator in Ontario, Quebec, and the Maritime provinces to apply the criteria described in PRC-006-NPCC-1 Attachment A to determine the compensatory load shedding that is required in Requirement R16 part 16.3 for generating units in its respective NPCC area.

Requirement R18 requires each Generator Owner, Distribution Provider, or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO to apply the criteria described in PRC-006-NPCC-1 Attachment B to determine the compensatory load shedding that is required in Requirement R16 part 16.3 for generating units in its respective NPCC area.

Requirement R19 requires each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in PRC-006-NPCC-1 Figure 1, based on their licensing design basis, to:

19.1 Set the underfrequency protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8Hz.

19.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.

19.3 Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.

Requirement R20 requires each Planning Coordinator to update its UFLS program database as specified by the NERC UFLS Reliability Standard on UFLS (currently PRC-006-1). This database shall include the following information:

20.1 For each UFLS relay, including those used for compensatory load shedding, the amount and location of load shed at peak, the corresponding frequency threshold and time delay settings.

20.2 The buses at which the Load is modeled in the NPCC library power flow case.

20.3 A list of all generating units that may be tripped for underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in PRC-006-NPCC-1 Figure 1, including the frequency trip threshold and time delay for each protection system.

20.4 The location and amount of additional elements to be switched for voltage control that are coordinated with UFLS program tripping.

20.5 A list of all UFLS relay inhibit functions along with the corresponding settings and locations of these relays.

Requirement R21 requires each Planning Coordinator to notify each Distribution Provider, Transmission Owner, and Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program performance characteristics as specified by the NERC PRC Standard on UFLS, which is currently PRC-006-1.

Requirement R22 requires each Distribution Provider, Transmission Owner and Generator Owner to implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R21.

Requirement R23 requires each Distribution Provider, Transmission Owner and Generator Owner to develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21.

6. Proposed Reliability Standards must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation

> Order No. 672 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.

The proposed Regional Reliability Standard includes a Violation Risk Factor ("VRF") and at least one Violation Severity Level ("VSL") for each requirement. The ranges of penalties for violations will be based on the applicable VRF and VSL and will be administered based on the sanctions table and supporting penalty determination process described in the FERC-approved NERC Sanction Guidelines.[14]

NPCC developed the VSLs and VRFs proposed for assignment to PRC-006-NPCC-1 following applicable NERC and FERC guidance. **Exhibit E** to this filing contains the VSL and VRF guideline analysis for PRC-006-NPCC-1.

7. 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.

> 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.

Each requirement of PRC-006-NPCC-1 has an associated measure of compliance that will assist those enforcing the standard in enforcing it in a consistent and non-preferential manner. The proposed measures are as follows:

[14] NERC Rules of Procedure Appendix 4B. Available at: http://www.nerc.com/page.php?cid=1|8|169.

M1. Each Planning Coordinator shall have evidence such as reports, system studies and/or real time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

M2. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

M3. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3.

M4. Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped, and the corresponding frequency thresholds, on those circuits included in its UFLS program to achieve the individual and cumulative percentages identified in Requirement R4. (PRC-006-NPCC-1 Attachment C Tables 1-3).

M5. Each Distribution Provider or Transmission Owner shall have evidence such as reports, analysis, system studies and dated documentation that demonstrates that it meets Requirement R5.

M6. Each Distribution Provider and Transmission Owner in the Québec Interconnection shall have evidence such as documentation or reports containing the location and amount of load to be tripped and the corresponding frequency thresholds on those circuits included in its UFLS program to achieve the load values identified in Table 4 of Requirement R6. (PRC-006-NPCC-1 Attachment C Table 4).

M7. Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R7.

M8. Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R8.

M9. Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R9.

M10. Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets or other documentation that demonstrates that it meets Requirement R10.

M11. Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R11.

M12. Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the frequency set point, the net amount of load shed and the percentage of its peak load at each stage of its UFLS program coincident with the integrated hourly peak of the previous year that demonstrates that it meets Requirement R12.

M13. Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R13.

M14. Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R14.

M15. Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R15.

M16. Each Generator Owner with existing non-nuclear units in service prior to the effective date of this Standard which have underfrequency tripping that is not compliant with Requirement R13 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R16.

M17. Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall provide evidence such as emails, memorandum or other documentation that demonstrates that it followed the methodology described in PRC-006-NPCC-1 Attachment A and meets Requirement R17.

M18. Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall provide evidence such as emails, memorandum, or other documentation that demonstrates that it followed the methodology described in PRC-006-NPCC-1 Attachment B and meets Requirement R18.

M19. Each Generator Owner of nuclear units that have been specifically identified by NPCC as having generator trip settings above the generator trip curve in PRC-006-NPCC-1 Figure 1 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R19.

M20. Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the requirements of Requirement R20.

M21. Each Planning Coordinator shall provide evidence such as emails, memorandum or other dated documentation that it meets Requirement R21.

M22. Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as reports, spreadsheets or other documentation that demonstrates that it meets Requirement R22.

M23. Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates it meets Requirement R23.

8. 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.

> Order No. 672 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

Regional Reliability Standard PRC-006-NPCC-1 achieves its reliability goal effectively and efficiently. The standard accomplishes the reliability goal of ensuring the development of an effective UFLS program in the NPCC region that preserves the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS Reliability Standard characteristics, which is currently contained in PRC-006-1.

The implementation plan for PRC-006- NPCC-1 (included in **Exhibit A**) specifies a six year implementation schedule and provides for annual improvement over that period in the system performance expected following UFLS operation for an island condition. Modifications to the program in the first two years are limited to relay setting changes only. Modifications requiring capital improvements are scheduled to begin in the third year of the program to provide sufficient time for including expenditures in capital budgets and procuring equipment.

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

> Order No. 672 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, [FERC] will not hesitate to remand a proposed Reliability Standard if [FERC is] convinced it is not adequate to protect reliability.

This proposed Regional Reliability Standard does not reflect a "lowest common denominator" approach. PRC-006-NPCC-1 incorporates the UFLS program recommendations set forth by the SS-38 Working Group on Inter-Area Dynamic Analysis in assessment studies that were performed after the 2003 Blackout. Contrary to a "lowest common denominator" approach, the Standard attempts to provide a bridge between the recommendations of the SS-38 Working Group and the current Registry Criteria by requiring the Planning Coordinator to identify those generators deemed critical to the performance of the UFLS program in order for the Regional Entity to review the status of such units.

10. Proposed Reliability Standards may consider costs to implement for smaller entities but not at consequence of less than excellence in operating system 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.

PRC-006-NPCC-1 provides an opportunity for smaller entities to aggregate their load with other such entities in the same electrical island. This allows each smaller entity's respective Planning Coordinator to achieve the desired aggregate outcome within that island according to the program characteristics.

11. 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 area or approach.

> Order No. 672 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.

The proposed Regional Reliability Standard is designed on a regional basis and will only apply to the NPCC region. It is not intended to be applied throughout North America.

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

> Order No. 672 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.

This proposed Regional Reliability Standard will not cause undue negative effects on competition or restriction of the grid. Because this standard will be applied equally across the NPCC region, PRC-006-NPCC-1 will not negatively affect competition, or restrict available transmission capability within the NPCC footprint.

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

> Order No. 672 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.

The implementation plan for the Regional Reliability Standard proposes a phased in implementation schedule as follows:

For the Eastern Interconnection and Québec Interconnection Portions of NPCC excluding the Independent Electricity System Operator ("IESO") Planning Coordinator Area of NPCC in Ontario, Canada:[15]

The effective date for requirements R1, R2, R3, R4, R5, R6, and R7 is the first day of the first calendar quarter following applicable regulatory approval but no

[15] Information regarding the implementation plan for the IESO and Québec Interconnection are for the Commission's information only.

earlier than Jan 1, 2016. The effective date for requirements R8 through R23 is the first day of the first calendar quarter two years following applicable governmental and regulatory approval.

For the IESO Planning Coordinator's Area of NPCC in Ontario, Canada:

All requirements are effective the first day of the first calendar quarter following applicable governmental and regulatory approval but no earlier than April 1, 2017.

The information submitted by NPCC supports the implementation schedule presented.

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

> Order No. 672 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 [FERC]-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].

NPCC develops Regional Reliability Standards in accordance with **Exhibit C** (*Regional Reliability Standards Development Procedure*) of its Regional Delegation Agreement with NERC. The development process is open to any person or entity with a legitimate interest in the reliability of the bulk power system. NPCC considers the comments of all stakeholders and an affirmative vote of the stakeholders and the NPCC Board of Directors are both required to approve a Regional Reliability Standard for submission to NERC and FERC.

The proposed Regional Reliability Standard has been developed and approved by industry stakeholders using NPCC's *Regional Reliability Standards Development Procedure* and was approved by the NPCC Board of Directors on November 20, 2011. The standard was subsequently presented to and approved by the NERC Board of Trustees February 9, 2012. Therefore, NPCC has utilized its standard development process in good faith and in a manner that is open and fair. No commenters disagreed with the open and fair implementation of the NPCC process.

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

> Order No. 672 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.

Neither NERC nor NPCC believes there are competing public interests with the request for approval of this proposed Regional Reliability Standard. No comments were received that indicated the proposed standard conflicts with other vital public interests. Therefore it is not necessary to balance this Regional Reliability Standard against any other competing public interests.

16. Proposed Reliability Standard must not conflict with prior FERC Rules or Orders.

> Order No. 672 at P 444. A potential conflict between a Reliability Standard under development and a Transmission Organization function, rule, order, tariff, rate schedule, or agreement accepted, approved, or ordered by the Commission should be identified and addressed during the ERO's Reliability Standard Development Process.

The proposed PRC-006-NPCC-1 Regional Reliability Standard does not conflict with any other prior FERC rules or orders and adequately addresses the directives identified in FERC Order No. 693.[16]

NERC has therefore determined that the proposed standard meets the criteria for consideration and approval as a Reliability Standard.

c. Additional Order No. 672 Criteria for Regional Reliability Standards

FERC's Order No. 672 also establishes additional criteria that a Regional Reliability Standard must satisfy: "A regional difference from a continent-wide Reliability Standard must either be (1) more stringent than the continent-wide Reliability Standard including a regional difference that addresses matters the continent-wide Reliability Standard does not, or (2) a Regional Reliability Standard that is necessitated by a physical difference in the Bulk-Power System."[17] The proposed standard satisfies these additional criteria.

The existing NERC continent-wide standard, PRC-006-1 – Automatic Underfrequency Load Shedding applies only to Planning Coordinators, Transmission Owners, and Distribution Providers. The proposed standard, PRC-006-NPCC-1, includes Generator Owners as applicable entities. The NPCC standard adds specificity not contained in the NERC standard for development and implementation of a UFLS program in the NPCC region that effectively arrests declining frequency, assists recovery following underfrequency events, and provides last resort system preservation measures. PRC-006-NPCC-1 achieves a coordinated, comprehensive UFLS region-wide consistent

[16] Order No. 693 at P 1480.
[17] Order No. 672 at P 291.

program within the NPCC Region and provides the regional requirements necessary to achieve and facilitate the broader program characteristics contained in the requirements of the NERC UFLS standard. It is designed to work in conjunction with, and augment the NERC standard by mitigating the consequences of an underfrequency event, while accommodating differences in system transmission and distribution topology among NPCC Planning Coordinators due to historical design criteria, makeup of load demands, and generation resources. The standard also facilitates uniformity, compliance, and clearly delineates what the applicable entities' requirements are within the region to achieve a robust, reliable and effective UFLS program. Thus, the proposed standard satisfies the additional Order No. 672 criteria for Regional Reliability Standards.

V. SUMMARY OF THE REGIONAL RELIABILITY STANDARD DEVELOPMENT PROCEEDINGS

NERC Evaluation: On November 21, 2011, NPCC submitted the proposed Regional Reliability Standard for evaluation and approval to NERC in accordance with NERC's *Rules of Procedure* and *Regional Reliability Standards Evaluation Procedure*[18] that was approved by NERC's Regional Reliability Standards Working Group. NERC provided its evaluation of the proposed PRC-006-NPCC-1 standard to NPCC on December 23, 2011, included in **Exhibit B**, after NERC concluded its 45-day posting of the standard.

Key Issues:

The NPCC drafting team for PRC-006-NPCC-1 considered and resolved a number of issues concerning the regional UFLS program and incorporated those outcomes into the requirements of this standard. The drafting team sought the

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[18] Regional Reliability Standards Evaluation Procedure, Version 1 (2009). Available at: http://www.nerc.com/docs/sac/rrswg/NERC_Regional_Reliability_Evaluation_Procedure.pdf.

recommendations of the NPCC SS-38 Working Group in order to ensure that its solutions to the issues brought forth by commenters and drafting team members were consistent with maintaining a regional effective program for all of the scenarios considered.

Among the issues resolved were: 1) generator coordination and the administration of compensatory load shedding for non-conforming generators, 2) participation of small entities in the regional UFLS program, 3) program tolerances 4) inhibit settings, 5) generator applicability, and 6) NERC PRC-006-1 coordination.

1) Generator Coordination and Compensatory Load Shedding:

The drafting team established a requirement for all new generators to conform to the generator tripping curve in the standard, thereby eliminating the problem of non-conforming generators in the future. Existing units that are already interconnected and in commercial operations that do not conform to the generator tripping curve in the standard currently obtain compensatory load shedding in accordance with existing NPCC procedures currently in effect and contained within NPCC Directory#12 Underfrequency Load Shedding Program Requirements.[19] These procedures are appended to the standard as attachments and provide the instructions for a non-conforming generator to obtain compensatory load shedding.

The drafting team also considered the existing nuclear units within NPCC with under-frequency threshold settings above the generator tripping curve. A requirement was developed that instructs these units to set the frequency trip setting upper tolerance as low as possible in accordance with the plant design and licensing limitations and to transmit the settings and any changes to settings to the Planning Coordinator.

[19] NPCC Directory # 12, *supra* note 12.

2) Small Entity Participation:

The NPCC UFLS program characteristics as developed by the NPCC SS-38 Working Group and implemented by NPCC area Planning Coordinators is designed with five discrete stages of load shedding (including an anti-stall stage) with approximately 7% of load shedding at each of the program stages. However, many smaller entities (typically those with less than 100MW) are constrained by facility design but with the technical support of the NPCC SS-38 group the drafting team developed modified program stages and tolerances for these smaller entities. The NPCC SS-38 Working Group modeled these small entity parameters to ensure that the overall regional program converged using these attributes. Furthermore, these small entity characteristics have already been incorporated within the regional UFLS criteria and included in NPCC Directory#12 Underfrequency Load Shedding Program Requirements.[20]

3) Program Tolerances:

The drafting team with the support of the NPCC SS-38 Working Group examined the tolerances that could be permitted when implementing the individual program stages of load shedding in 7% blocks. NPCC SS-38 recommended that the upper and lower program tolerances at each stage should be bounded by +/- 0.5% surrounding a nominal amount of load shed at each stage (7%). This recommendation was incorporated into the standard and provides entities designing their UFLS programs with some degree of flexibility when assigning the amount of load to be shed on declining frequency.

4) Inhibit Settings:

The drafting team recognized during the development of the standard that various inhibit thresholds designed to prevent the misoperation of UFLS relays are employed

[20] NPCC Directory # 12, *supra* note 12.

throughout the region. Although the most common feature is a voltage inhibit, other inhibit schemes utilizing current and time were also revealed. Additionally, the application of the voltage inhibit function was not consistent across the region.

Accordingly, the drafting team developed a requirement for each Planning Coordinator to review and coordinate the development of these thresholds to insure that they are consistent with the goal of an effective regional UFLS program.

5) Generator Applicability:

The drafting team considered the unique nature of UFLS with respect to the critical issue of maintaining proper generator coordination for all units determined to be critical to the support of the UFLS program performance characteristics. The NPCC SS-38 Working Group's assessments and recommendations were developed into a requirement that will allow the Planning Coordinators to identify generation facilities within its Planning Coordinator Area that are considered critical to the program's performance.

6) Coordination with NERC PRC-006-1.

The NPCC drafting team developed PRC-006-NPCC-1 in a manner that coordinated with NERC Reliability Standard PRC-006-1 — Automatic Underfrequency Load Shedding. In some cases, draft requirements were eliminated from the Regional Reliability Standard since PRC-006-1 already includes a requirement in place for these program attributes (e.g. perform a program design assessment every 5 years). In other cases the requirements in the Regional Standard enhance the existing requirements in the NERC Standard as a necessary requirement for the Regional program. For example, NERC PRC- 006-1 has a requirement to "establish islands" and PRC -006-NPCC-1 has a requirement to "use islands to aggregate load." In still other cases, the drafting team developed requirements to be included in the Regional Standard that were not covered in NERC's PRC-006-1 and which were critical to the performance of the Regional program, such as inhibit thresholds and time delay characteristics on UFLS relays.

Violation Risk Factors and Violation Severity Levels:

The proposed Regional Reliability Standard contains both VRFs and VSLs. VRFs and VSLs are assigned to each requirement in the standard. The VRFs and VSLs for this standard were developed and reviewed for consistency with NERC and FERC guidelines.[21] Analyses of the assigned VRFs and VSLs to this standard are included in **Exhibit E**.

VI. <u>CONCLUSION</u>

For the reasons stated above, NERC respectfully requests that FERC approve the proposed PRC-006-NPCC-1 Regional Reliability Standard and the associated proposed VRFs and VSLs included in **Exhibit A** to this filing in accordance with Section 215(d)(1) of the FPA and Part 39.5 of FERC's regulations. NERC requests that these approvals be made effective in accordance with the implementation plan for PRC-006-NPCC-1 included in **Exhibit A** to this filing.

Respectfully submitted,

<u>*/s/ Andrew M. Dressel*</u>
Andrew M. Dressel
Attorney for North American Electric Reliability Corporation

[21] *See Order on Violation Risk Factors*, 119 FERC ¶ 61,145 (2007) and *Order on Violation Severity Levels Proposed by the Electric Reliability Organization*, 123 FERC ¶ 61,284 (2008).

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 4th day of May, 2012.

/s/ Andrew M. Dressel
Andrew M. Dressel
Attorney for North American Electric Reliability Corporation

Exhibit A

PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding Regional Reliability Standard Proposed and Implementation Plan for Approval

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**
2. **Number:** PRC-006-NPCC-1
3. **Purpose:** To provide a regional reliability standard that ensures the development of an effective automatic underfrequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS reliability standard characteristics.
4. **Applicability:**
   - **4.1.** Generator Owner
   - **4.2.** Planning Coordinator
   - **4.3.** Distribution Provider
   - **4.4.** Transmission Owner
5. **(Proposed) Effective Date:** To be established.

B. Requirements

R1 Each Planning Coordinator shall establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding based on islanding criteria (required by the NERC PRC Standard on UFLS). [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R2 Each Planning Coordinator shall, within 30 days of completion of its system studies required by the NERC PRC Standard on UFLS, identify to the Regional Entity the generation facilities within its Planning Coordinator Area necessary to support the UFLS program performance characteristics. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R3 Each Planning Coordinator shall provide to the Transmission Owner, Distribution Provider, and Generator Owner within 30 days upon written request the requirements for entities aggregating the UFLS programs and requirements for compensatory load shedding program derived from each Planning Coordinator's system studies as determined by Requirement R1. [Violation Risk Factor: Low] [Time Horizon: Long Term Planning]

R4 Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program reflecting normal operating conditions excluding outages for its Facilities based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3, or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1 and acting as a single entity, provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load, based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R5 Each Distribution Provider or Transmission Owner that must arm its load to trip on underfrequency in order to meet its requirements as specified and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4 above, as applicable depending on its total peak net Load shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

5.1 Inform its Planning Coordinator of the need to exceed the stated tolerances or the number of stages as shown in UFLS Attachment C, Table 1 if applicable and

5.2 Provide its Planning Coordinator with a technical study that demonstrates that the Distribution Providers or Transmission Owners specific deviations from the requirements of UFLS Attachment C, Table 1 will not have a significant adverse impact on the bulk power system.

5.3 Inform its Planning Coordinator of the need to exceed the stated tolerances of UFLS Attachment C, Table 2 or Table 3, and in the case of Attachment C, Table 2 only, the need to deviate from providing two stages of UFLS, if applicable, and

5.4 Provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Attachment C Table 2 or Attachment C Table 3.

R6 Each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R7 Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with the following minimum time delay:

7.1 Eastern Interconnection – 100 ms

7.2 Québec Interconnection – 200 ms

[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R8 Each Planning Coordinator shall develop and review once per calendar year settings for inhibit thresholds (such as but not limited to voltage, current and time) to be utilized within its region's UFLS program. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R9 Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 days of the initial determination of those inhibit thresholds and within 30 days of any changes to those thresholds. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

R10 Each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R9. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

R11 Each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R9. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R12 Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage coincident with their integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would be opened by the UFLS relays. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]

R13 Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in Requirements R16 and R19. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R14 Each Generator Owner shall transmit the generator underfrequency trip setting and time delay to its Planning Coordinator within 45 days of the Planning Coordinator's request. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

R15 Each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard, or an existing generator increasing its net capability by greater than 10% shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

15.1 Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 1.

15.2 Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1.

R16 Each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1 shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

16.1 Set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

16.2 Transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

16.3 Have compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of their generator due to early tripping.

R17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall apply the criteria described in Attachment B to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R19 Each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 1, based on their licensing design basis, shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

19.1 Set the underfrequency protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8Hz.

19.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.

19.3 Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.

R20 The Planning Coordinator shall update its UFLS program database as specified by the NERC PRC Standard on UFLS. This database shall include the following information: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

20.1 For each UFLS relay, including those used for compensatory load shedding, the amount and location of load shed at peak, the corresponding frequency threshold and time delay settings.

20.2 The buses at which the Load is modeled in the NPCC library power flow case.

20.3 A list of all generating units that may be tripped for underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, including the frequency trip threshold and time delay for each protection system.

20.4 The location and amount of additional elements to be switched for voltage control that are coordinated with UFLS program tripping.

20.5 A list of all UFLS relay inhibit functions along with the corresponding settings and locations of these relays.

R21 Each Planning Coordinator shall notify each Distribution Provider, Transmission Owner, and Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program performance characteristics as specified by the NERC PRC Standard on UFLS.[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R22 Each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R23 Each Distribution Provider, Transmission Owner and Generator Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

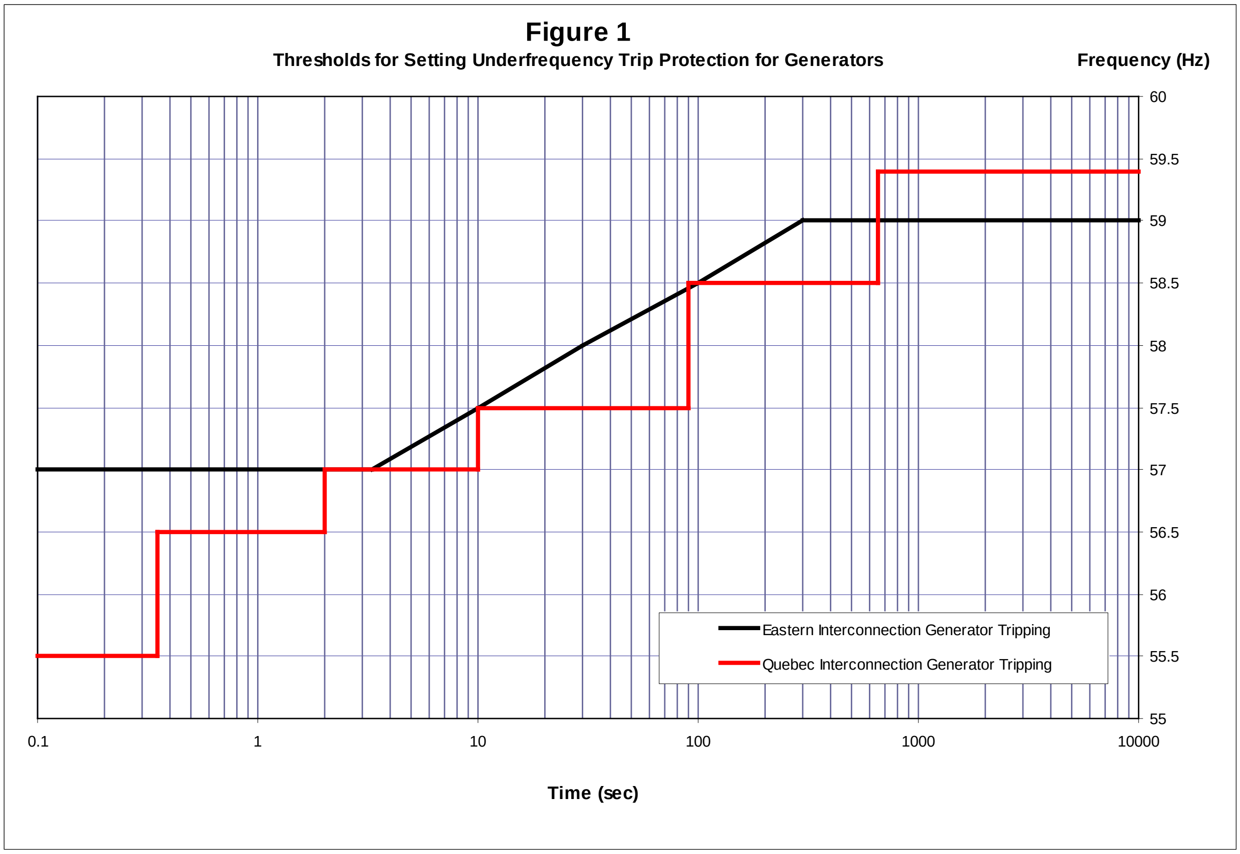
Figure 1
Thresholds for Setting Underfrequency Trip Protection for Generators
Frequency (Hz)
60
59.5
59
58.5
58
57.5
57
56.5
56
55.5
55
0.1
1
10
100
1000
10000
Time (sec)
Eastern Interconnection Generator Tripping
Quebec Interconnection Generator Tripping

C. Measures

M1 Each Planning Coordinator shall have evidence such as reports, system studies and/or real time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

M2. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

M3 Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3.

M4 Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped, and the corresponding frequency thresholds, on those circuits included in its UFLS program to achieve the individual and cumulative percentages identified in Requirement R4. (Attachment C Tables 1-3).

M5 Each Distribution Provider or Transmission Owner shall have evidence such as reports, analysis, system studies and dated documentation that demonstrates that it meets Requirement R5.

M6 Each Distribution Provider and Transmission Owner in the Québec Interconnection shall have evidence such as documentation or reports containing the location and amount of load to be tripped and the corresponding frequency thresholds on those circuits included in its UFLS program to achieve the load values identified in Table 4 of Requirement R6. (Attachment C Table 4).

M7 Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R7.

M8 Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R8.

M9 Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R9.

M10 Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets or other documentation that demonstrates that it meets Requirement R10.

M11 Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R11.

M12 Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the frequency set point, the net amount of load shed and the percentage of its peak load at each stage of its UFLS program coincident with the integrated hourly peak of the previous year that demonstrates that it meets Requirement R12.

M13 Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R13.

M14 Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R14.

M15 Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R15.

M16 Each Generator Owner with existing non-nuclear units in service prior to the effective date of this Standard which have underfrequency tripping that is not compliant with Requirement R13 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R16.

M17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall provide evidence such as emails, memorandum or other documentation that demonstrates that it followed the methodology described in Attachment A and meets Requirement R17.

M18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall provide evidence such as emails, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R18.

M19 Each Generator Owner of nuclear units that have been specifically identified by NPCC as having generator trip settings above the generator trip curve in Figure 1 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R19.

M20 Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the requirements of Requirement R20.

M21 Each Planning Coordinator shall provide evidence such as emails, memorandum or other dated documentation that it meets Requirement R21.

M22 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as reports, spreadsheets or other documentation that demonstrates that it meets Requirement R22.

M23 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates it meets Requirement 23.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

NPCC Compliance Committee

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable

1.3. Data Retention

The Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 4, 5, 6,7,10, 11, and 12.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 3, 8, 9, 20, and 21.

The Planning Coordinator in Ontario, Quebec, and the Maritime Provinces shall keep evidence for three calendar years for Measure 17.

The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measures 18, 22, and 23.

The Generator Owner shall keep evidence for three calendar years for Measures 13, 14, 15, 16, and 19.

1.4. Compliance Monitoring and Assessment Processes

Self -Certifications.

Spot Checking.

Compliance Audits.

Self- Reporting.

Compliance Violation Investigations.

Complaints.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	**N/A**	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs. or Did not establish requirements for compensatory load shedding.	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs and did not establish requirements for compensatory load shedding.
R2	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 30 days but less than 41 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 40 days but less than 51 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 50 days but less than 61 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 60 days after completion of the system studies. or The Planning Coordinator did not identify the generation facilities within its Planning Coordinator Area necessary to support the UFLS program.
R3	The Planning Coordinator provided the requested information, but did so more than 30 days but less than 41 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 40 days but less than 51 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 50 days but less than 61 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 60 days after the request. or The Planning Coordinator failed to provide the requested information.

R4	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to implement an automatic UFLS program reflecting normal operating conditions excluding outages, for its Facilities or collectively implemented by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on frequency thresholds, total nominal operating time, and amounts specified in the appropriate included tables.
R5	N/A	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not inform the Planning Coordinator of the need to exceed the stated tolerances of UFLS Table 2 or Table 3, and in the case of Table	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not provide the Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or	The Distribution Provider or Transmission Owner did not arm its load to trip on underfrequency in order to meet its minimum obligations and in doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load.

		2 only, the need to deviate from providing two stages of UFLS.	Transmission Owner to comply with the appropriate table.	
R6	N/A	N/A	T	The Distribution Provider or Transmission Owner in the Québec Interconnection portion of NPCC did not implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or did not collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4.
R7	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to set

				an underfrequency relay that is part of its region's UFLS program as specified in Requirement R7.
R8		N/A	The Planning Coordinator developed inhibit thresholds as specified in Requirement R8 but did not perform the review once per calendar year.	The Planning Coordinator did not develop inhibit thresholds as specified in Requirement R8.
R9	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 30 days but less than 41 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 40 days but less than 51 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 50 days but less than 61 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 60 days after the initial determination or any subsequent change to the inhibit thresholds. or The Planning Coordinator did not provide to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds.
R10	N/A	N/A	N/A	The Distribution Provider or Transmission Owner did not implement the inhibit threshold based on the notification provided by the Planning Coordinator in accordance with Requirement R9.

R11	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider or Transmission Owner did not develop its implementation plan.
R12				The Transmission Owner or Distribution Provider did not provide documentation to its Planning Coordinator of actual net load data or updates to the data that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year.
R13	N/A	N/A	N/A	The Generator Owner did not set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted.

R14	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 45 days and less than 56 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 55 days and less than 66 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 65 days and less than 76 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 75days after the Planning Coordinator's request. or The Generator Owner did not transmit the generator underfrequency trip setting and time delay to its Planning Coordinator.
R15	N/A	N/A	The Generator Owner did not fulfill the obligation of Requirement R15; Part 15.1 OR did not fulfill the obligation of Requirement R15, Part 15.2.	The Generator Owner did not fulfill the obligation of Requirement R15, Part 15.1 and did not fulfill the obligation of Requirement R15, Part 15.2.
R16	N/A	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.2.	The Generator Owner did not fulfill the obligation of Requirement R16; Part 16.1 OR did not fulfill the obligation of Requirement R16, Part 16.3.	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.1 and did not fulfill the obligation of Requirement R16, Part 16.3.

R17	N/A	N/A	N/A	The Planning Coordinator did not apply the methodology described in Attachment A to determine the compensatory load shedding that is required.
R18	N/A	N/A	N/A	The Generator Owner, Distribution Provider, or Transmission Owner did not apply the methodology described in Attachment B to determine the compensatory load shedding that is required.
R19	N/A	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.3.	The Generator Owner did not fulfill the obligation of Requirement R19; Part 19.1 OR did not fulfill the obligation of Requirement R19, Part 19.2.	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.1 and did not fulfill the obligation of Requirement R19, Part 19.2.
R20	The Planning Coordinator did not have data in its database for one of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for two of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for three of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for four or more of the parameters listed in Requirement 20, Parts 20.1 through 20.5.

R21	N/A	N/A	N/A	The Planning Coordinator did not notify a Distribution Provider, Transmission Owner, or Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program requirements.
R22	N/A	N/A	N/A	The Distribution Provider, Transmission Owner, or Generator Owner did not implement the load distribution changes based on the notification provided by the Planning Coordinator.
R23	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider. Transmission Owner or Generator Owner did not develop its implementation plan.

PRC-006-NPCC-1 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with underfrequency protections set to trip above the appropriate curve in Figure 1. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all islands identified in Requirement R1 in which the unit may operate.

The methodology below provides a set of criteria for the Planning Coordinator to follow for determining compensatory load shedding requirements:

1. The Planning Coordinator shall identify, compile and maintain an updated list of all existing non-nuclear generating units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1. The list shall include the following information for each unit:

   1.1 Generator name and generating capacity
   1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
   1.3 Physical and electrical location of the unit
   1.4 All islands within which the unit may operate, as identified in Requirement R1

2. For each generating unit identified in (1) above, the Planning Coordinator shall establish the requirements for compensatory load shedding based on criteria outlined below:

   2.1 Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator in Requirement R1 within which the generator may operate to provide compensatory load shedding.

   2.2 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4..

   2.3 The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 during an underfrequency event. If the highest

frequency at which the subject generator will trip above the appropriate curve in Figure 1 does not correspond to a specific UFLS program stage threshold setting, the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1.

2.4 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment B

Compensatory Load Shedding Criteria for ISO-NE and NYISO:

The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 1 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements:

1. The Generator Owner shall identify and compile a list of all existing non-nuclear generating units in service prior to the effective date of this standard that has underfrequency protection set to trip above the appropriate curve in Figure 1. The list shall include the following information associated with each unit:

   1.1 Generator name and generating capacity
   1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
   1.3 Physical and electrical location of the unit
   1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.

2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:

   2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 1, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

   2.2 In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 1, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

   2.3 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.4 The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip.

2.5 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment C

UFLS Table 1: Eastern Interconnection Distribution Providers and Transmission Owners with 100 MW or more of peak net Load shall implement a UFLS program with the following attributes:			
Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
59.5	0.30	6.5 – 7.5	6.5 – 7.5
59.3	0.30	6.5 – 7.5	13.5 – 14.5
59.1	0.30	6.5 – 7.5	20.5 – 21.5
58.9	0.30	6.5 – 7.5	27.5 – 28.5
59.5	10.0	2 – 3	29.5 – 31.5

UFLS Table 2: Eastern Interconnection Distribution Providers and Transmission Owners with 50 MW or more and less than 100 MW of peak net Load shall implement a UFLS program with the following attributes:				
UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time(s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	14-25	14-25
2	59.1	0.30	14-25	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 3: Eastern Interconnection Distribution Providers and Transmission Owners with 25 MW or more and less than 50 MW of peak net Load shall implement a UFLS program with the following attributes:				
UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	28-50	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 4: Quebec Interconnection

	Rate	Frequency (Hz)	MW at peak (*Load must be fixed at all times when above 60% of peak load..)	Mvar at peak	Total Nominal Operating Time (s) [2]
Threshold Stage 1	——	58.5	1000*	1000	0.30
Threshold Stage 2	——	58.0	800*	800	0.30
Threshold Stage 3	——	57.5	800	800	0.30
Threshold Stage 4	——	57.0	800	800	0.30
Threshold Stage 5 (anti-stall)	——	59.0	500	500	20.0
Slope Stage 1	-0.3 Hz/s	58.5	400	400	0.30
Slope Stage 2	-0.4 Hz/s	59.8	800*	800	0.30
Slope Stage 3	-0.6 Hz/s	59.8	800*	800	0.30
Slope Stage 4	-0.9 Hz/s	59.8	800	800	0.30

2. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time. The underfrequency relay operating time shall be measured from the time when the frequency passes through the frequency threshold set point.

Exhibit B

Complete Development Record of Proposed PRC-006-NPCC-1 Automatic Underfrequency Load Shedding Regional Reliability Standard

Regional Reliability Standards - Under Development				
Standard No.	**Title**	**Regional Status**	**Dates**	**NERC Status**
Northeast Power Coordinating Council (NPCC)				
PRC-006-NPCC-01	Automatic Underfrequency Load Shedding Program	NERC Board Adopted February 9, 2012	11/22/11-12/22/11	Info **(12)** Submit Comments Comment Form **(11)** PRC-006-NPCC-1**(10)** Implementation Plan **(9)** Comments Received **(8)** Consideration of Comments **(7)**
			01/11/11-02/24/11	Submit Comments Comment Form **(6)** PRC-006-NPCC-1 **(5)** Implementation Plan **(4)** Consideration of Comments **(3)** PRC-006-NPCC-1 **(2)** Implementation Plan **(1)**

NPCC, Inc.

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PRC-006-NPCC-1 Automatic Underfrequency Load Shedding

Implementation Plan

Background:

The purpose of this draft Regional Standard is to ensure the development and maintenance of an effective and coordinated Automatic Underfrequency Load Shedding program in order to preserve the reliability and integrity of the bulk power system during declining system frequency events.

In the developing the Implementation Plan for PRC-006-NPCC-01 the Standard Drafting Team considered the following:

1. The requirements listed in this Regional Standard are intended to cover all aspects of the UFLS program. The Regional Standard Drafting Team (RSDT) coordinated its development with the draft NERC UFLS Standard PRC-006. The intent of this Regional Standard is to be more stringent than the continent wide standard while incorporating specific program characteristics into the requirements.
2. The Implementation Plan for this standard is based, in part, on the timelines reflected in the existing and ongoing Implementation Plan for NPCC Directory #12 absent the annual milestones required by Directory #12.

Effective Dates:

Eastern Interconnection & Québec Interconnection Portions of NPCC Excluding the Independent Electricity System Operator (IESO) Planning Coordinator Area of NPCC in Ontario, Canada.

1. The effective date for requirements R1, R2, R3, R4, R5, R6, R7, R8, and R9 is the first day of the first calendar quarter following applicable regulatory approval but no earlier than Jan 1, 2016 to allow for the existing implementation plan to be completed.

2. The effective date for requirements R10 through R27 is the first day of the first calendar quarter two years following applicable governmental and regulatory approval.

Independent Electricity System Operator (IESO) Planning Coordinator's Area of NPCC in Ontario, Canada

1. Effective the first day of the first calendar quarter following applicable governmental and regulatory approval but no earlier than April 1, 2017.

References:

- 2006 Assessment of UFLS Adequacy Part 3 Assessment of Program Modifications.
- SS38 Underfrequency Load Shedding Support Studies

NPCC Criteria:

- Directory #12 Underfrequency Load Shedding Program Requirements.
- A-7 NPCC Glossary of Terms.

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. NPCC Regional Standards Committee (RSC) authorized posting UFLS RSAR development on August 20, 2008.
2. UFLS RSAR posted on NPCC website on August 25, 2008.
3. NPCC Reliability Coordinating Committee (RCC) approved the Task Force on System Studies (TFSS) as the lead task force to initiate drafting a UFLS Regional Standards on September 4, 2008.
4. NPCC UFLS Regional Standard Drafting Team initial meeting on January 27, 2009.
5. First draft posted on the NPCC Website July 13, 2009 for a 45 day comment period.
6. Second draft posted on the NPCC Website May 26, 2010 for a 45 day comment period.

Description of Current Draft:

This is the third draft of the proposed standard.

Future Development Plan:

Anticipated Action	Anticipated Date
1. Post the initial draft of the standard for 45 day comment period.	July 13, 2009 to August 27, 2009
2. Respond to comments on the first posting and post revised standard and implementation plan for a 45 day comment period.	September 2009 to May 2010 May 26, 2010 to July 9th, 2010
3. Respond to comments on the 2nd posting.	July 2010 to October 2010
4. Obtain RSC approval to move the standard forward to balloting.	November 2010
5. Post the standard and implementation plan for a 30 day pre ballot review.	December 2010
6. Conduct a ten day ballot.	December 2010

7. Respond to ballot comments and post revised standard and implementation plan for a 45 day comment period.	May, 2011.
8. Respond to comments on the 3rd posting.	July 2011
9. Obtain RSC approval to move the standard forward to balloting.	August 2011
10. Post the standard and implementation plan for a 30 day pre ballot review.	August 2011
11. Conduct a ten day ballot.	September 2011
12. Membership Approval.	September 2011.

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 NERC 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 NPCC Glossary.

In the standards, defined terms are indicated with its first letter capitalized.

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**
2. **Number:** PRC-006-NPCC-1
3. **Purpose:** To provide a regional reliability standard that ensures the development of an effective automatic underfrequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS reliability standard characteristics.
4. **Applicability:**
   - **4.1.** Generator Owner
   - **4.2.** Planning Coordinator
   - **4.3.** Distribution Provider
   - **4.4.** Transmission Owner
5. **(Proposed) Effective Date:** To be established.

B. Requirements

R1 Each Planning Coordinator shall conduct system studies and/or use real time power flow data captured from actual system events to identify anticipated islands within the NPCC region to establish requirements for entities aggregating their UFLS programs in Requirement R3 and R4 and requirements for compensatory load shedding in Requirement R18. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R2 Each Planning Coordinator shall, in accordance with its system studies, identify to the Regional Entity the generation facilities within its Planning Coordinator Area necessary to support the UFLS program performance characteristics. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R3 Each Planning Coordinator shall provide to Transmission Owners, Distribution Providers, and /or Generator Owners within thirty days upon written request the information on anticipated islands derived from each Planning Coordinator's system studies as determined by Requirement R1 and /or real time power flow data pertinent to requirements for aggregating UFLS programs and/or providing for compensatory load shedding. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R4 Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program, reflecting normal operating conditions excluding outages, for its Facilities or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on frequency thresholds, total nominal operating time, and amounts specified in one of the following tables: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

- Distribution Providers and Transmission Owners with 100 MW or more of peak net Load shall implement a UFLS program with the following attributes:

UFLS Table 1:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	6.5 – 7.5	6.5 – 7.5
2	59.3	0.30	6.5 – 7.5	13.5 – 14.5
3	59.1	0.30	6.5 – 7.5	20.5 – 21.5
4	58.9	0.30	6.5 – 7.5	27.5 – 28.5
Anti-Stall	59.5	10.0	2 – 3	29.5 – 31.5

- Distribution Providers and Transmission Owners with 50 MW or more and less than 100 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Table 2:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	14-25	14-25
2	59.1	0.30	14-25	28-50

- Distribution Providers and Transmission Owners with 25 MW or more and less than 50 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Table 3:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	28-50	28-50

R5 Each Distribution Provider or Transmission Owner that must arm its load to trip on under frequency in order to meet its requirements as specified and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4 above, as applicable depending on their total peak net Load shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning

5.1 Inform their Planning Coordinator of the need to exceed the stated tolerances of UFLS Table 1 if applicable and

5.2 Provide their Planning Coordinator with a technical study that demonstrates that the Distribution Providers or Transmission Owners specific deviations from the requirements of UFLS Table 1 will not have a significant adverse impact on the bulk power system.

5.3 Inform their Planning Coordinator of the need to exceed the stated tolerances of UFLS Table 2 or Table 3, and in the case of Table 2 only, the need to deviate from providing two stages of UFLS, if applicable, and

5.4 Provide their Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Table 2 or Table 3

R6 Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC with peak net Load connected to its Facilities shall ensure that the total nominal operating time includes the under frequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time, such that: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

6.1 The under frequency relay operating time shall be measured from the time the frequency passes through the frequency threshold set point, using a test rate of linear frequency decay of 0.2 Hz per second.

6.2 The underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second if the relay operating time is dependent on the rate of frequency decay.

R7 Each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in the following table: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

UFLS Table 4

	Rate	Frequency (Hz)	MW at peak (*Load must be fixed at all times.)	Mvar at peak	Total Nominal Operating Time (s)
Threshold Stage 1	——	58.5	1000*	1000	0.30
Threshold Stage 2	——	58.0	800*	800	0.30
Threshold Stage 3	——	57.5	800	800	0.30
Threshold Stage 4	——	57.0	800	800	0.30
Threshold Stage 5 (anti-stall)	——	59.0	500	500	20.0
Slope Stage 1	-0.3 Hz/s	58.5	400	400	0.30
Slope Stage 2	-0.4 Hz/s	59.8	800*	800	0.30
Slope Stage 3	-0.6 Hz/s	59.8	800*	800	0.30
Slope Stage 4	-0.9 Hz/s	59.8	800	800	0.30

R8 Each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC with peak net load connected to its Facilities shall insure that the total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time. The underfrequency relay operating time shall be measured from the time when the frequency passes through the frequency threshold set point.[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R9 Each Distribution Provider and Transmission Owner shall set their underfrequency relays with the following minimum time delay:

9.1 Eastern Interconnection – 100 ms

9.2 Québec Interconnection – 200 ms

[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R10 Each Planning Coordinator shall develop, implement and maintain a program to establish the appropriate inhibit thresholds (such as but not limited to voltage, current and time) to be utilized within its region's UFLS Program to insure that the inhibit settings do not adversely affect the UFLS program. [Violation Risk Factor: High] [Time Horizon: Long Term Planning

R11 Each Planning Coordinator shall provide to Transmission Owners and Distribution Providers within its program area the specific inhibit thresholds applicable to each Transmission Owner or Distribution Providers within 30 days of the initial determination of the required inhibit threshold settings or for changes to those settings. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

R12 Each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R11. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

R13 Each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R11. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

R14 Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net load that would be shed by the UFLS relays at each UFLS stage coincident with their integrated hourly peak during the previous year, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]

R15 Each Generator Owner shall set each generator under frequency trip relay, if so equipped, below the appropriate generator under frequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in Requirements R18 and R21. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R16 Each Generator Owner shall transmit the generator under frequency trip setting and time constant to its Planning Coordinator within 45 days of the Planning Coordinator's request. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

R17 Each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard, or an existing generator increasing its net capability by greater than 10% shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

17.1 Ensure that the generating unit does not trip directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 1.

17.2 Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during under frequency conditions above the appropriate generator under frequency trip protection settings threshold curve in Figure 1.

17.3 Transmit the generator underfrequency trip setting and time constant to the Planning Coordinator.

R18 Each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1 shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

18.1 Set the underfrequency protection to operate at the lowest frequency possible as demonstrated by the plant design and licensing limitations..

18.2 Transmit the existing under frequency settings and any changes to the under frequency settings along with the technical basis for the settings to the Planning Coordinator.

18.3 Have compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of their generator due to early tripping.

R19 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the methodology described in Attachment A to determine the compensatory load shedding that is required in Requirement R18.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R20 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall apply the methodology described in Attachment B to determine the compensatory load shedding that is required in Requirement R18.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R21 Each Generator Owner of existing nuclear generating plants with units that have under frequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 1, based on their licensing design basis, are required to adhere to the following: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

21.1 Set the under frequency protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8Hz.

21.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.

21.3 Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.

R22 Each Transmission Owner and Distribution Provider shall annually provide, with no more than 15 months between updates, its UFLS program data to its Planning Coordinator in accordance with R23 for inclusion in the Planning Coordinator's data base. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]

R23 Each Planning Coordinator shall develop and maintain its UFLS program data base. The Planning Coordinator shall update its UFLS program database within four months of receiving the Requirement R22 information. This data base shall include the following information: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

23.1 For each UFLS relay, including those used for compensatory load shedding, the amount and location of load shed at peak the corresponding frequency threshold and time delay settings.

23.2 The buses at which the Load is modeled in the NPCC library power flow case.

23.3 A list of all generating units that may be tripped for underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, including the frequency trip threshold and time delay for each protection system.

23.4 The location and amount of additional elements to be switched for voltage control that are coordinated with UFLS program tripping.

23.5 A list of all UFLS relay inhibit functions along with the corresponding settings and locations of these relays.

R24 Each Planning Coordinator shall assess that the NPCC UFLS program requirements within its Planning Coordinator area are satisfied as implemented by Transmission Owners, Distribution Providers, and Generator Owners. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

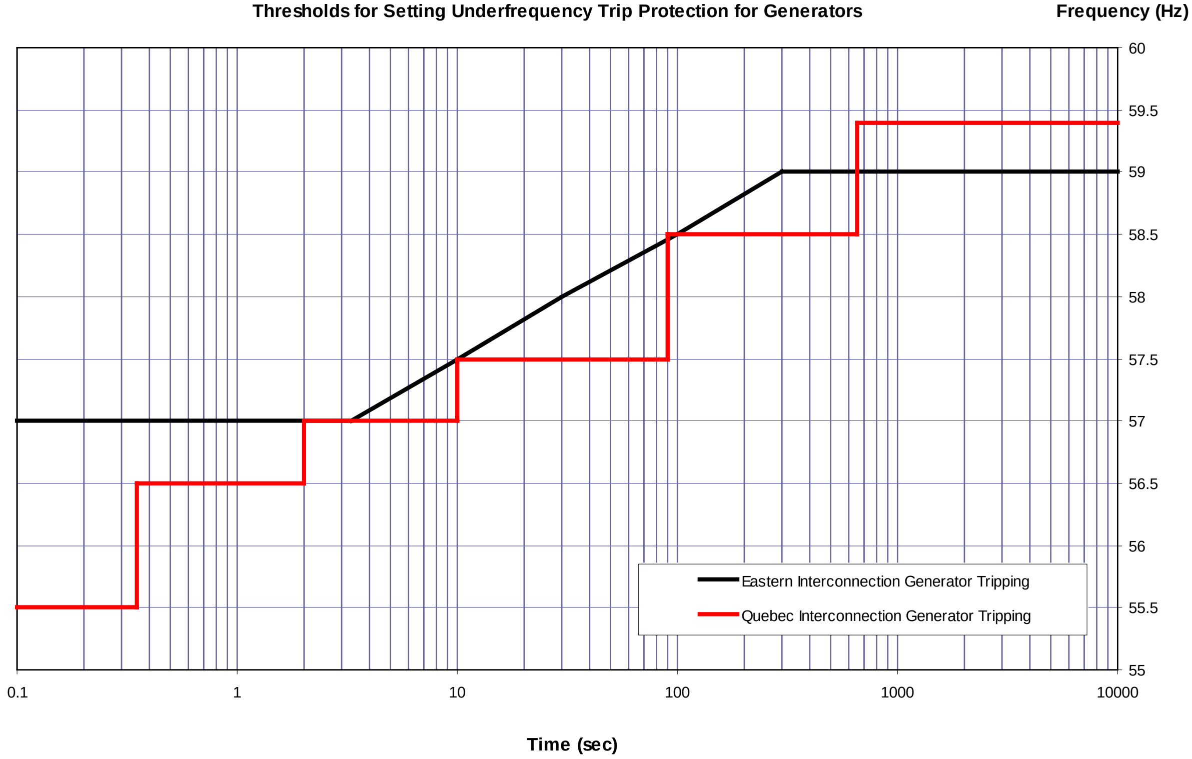
R25 Each Planning Coordinator shall notify Distribution Providers, Transmission Owners, and Generator Owners within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program requirements.[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R26 Each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R25. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R27 Each Distribution Provider, Transmission Owner and Generator Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R25. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

Figure 1

Thresholds for Setting Underfrequency Trip Protection for Generators



C. Measures

M1 Each Planning Coordinator shall have evidence such as reports, system studies and/or real time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

M2. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

M3 Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3.

M4 Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped, and the corresponding frequency thresholds, on those circuits included in its UFLS program to achieve the individual and cumulative percentages identified in Requirement R4.

M5 Each Distribution Provider or Transmission Owner shall have evidence such as reports, analysis, system studies and dated documentation that demonstrates that it meets Requirement R5.

M6 Each Distribution Provider and Transmission Owner shall have evidence such as reports, data sheets and other test documentation that demonstrates that it meets Requirement R6.

M7 Each Distribution Provider and Transmission Owner in the Québec Interconnection shall have evidence such as documentation or reports containing the location and amount of load to be tripped and the corresponding frequency thresholds on those circuits included in its UFLS program to achieve the load values identified in Table 4 of Requirement R7.

M8 Each Distribution Provider and Transmission Owner in the Québec Interconnection shall have evidence such as reports, data sheets and other test documentation that demonstrates that it meets Requirement R8.

M9 Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R9.

M10 Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R10.

M11 Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R11.

M12 Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets or other documentation that demonstrates that it meets Requirement R12.

M13 Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R13.

M14 Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the frequency set point, the net amount of load shed and the percentage of its peak load at each stage of its UFLS program coincident with the integrated hourly peak of the previous year that demonstrates that it meets Requirement R14.

M15 Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R15.

M16 Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R16

M17 Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R17.

M18 Each Generator Owner with existing non-nuclear units in service prior to the effective date of this Standard which have under frequency tripping that is not compliant with Requirement R14 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R18.

M19 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall provide evidence such as emails, memorandum or other documentation that demonstrates that it followed the methodology described in Attachment A and meets Requirement R19.

M20 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall provide evidence such as emails, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R20.

M21 Each Generator Owner of nuclear units that have been specifically identified by NPCC as having generator trip settings above the generator trip curve in Figure 1 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R21.

M22 Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets and other dated documentation that demonstrates that it meets Requirement R22.

M23 Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the requirements of Requirement R23.

M24 Each Planning Coordinator shall provide evidence such as reports, system studies and/or real time power flow data captured from actual system events that demonstrates that it meets the requirements of R24.

M25 Each Planning Coordinator shall provide evidence such as emails, memorandum or other dated documentation that it meets Requirement R25.

M26 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as reports, spreadsheets or other documentation that demonstrates that it meets Requirement R26.

M27 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates it meets Requirement R27

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

NPCC Compliance Committee

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable

1.3. Data Retention

The Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 4, 5, 6,7,8,9,12,13,14, and 22.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 3, 10, 11, 19, 23, 24, and 25.

The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measure 20, 26, and 27.

The Generator Owner shall keep evidence for three calendar years for Measures 15,16,17,18, and 21.

1.4. Compliance Monitoring and Assessment Processes

Self -Certifications.

Spot Checking.

Compliance Audits.

Self- Reporting.

Compliance Violation Investigations.

Complaints.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	**N/A**	N/A	The Planning Coordinator did not conduct system studies or use real time power flow data captured from actual system events to identify anticipated islands within the NPCC region used to establish requirements for entities aggregating their UFLS programs, and requirements for compensatory load shedding.
R2	N/A	N/A	N/A	The Planning Coordinator did not identify the generation facilities within its Planning Coordinator Area necessary to support the UFLS program.
R3	N/A	N/A	N/A	The Planning Coordinator failed to provide to Transmission Owners, Distribution Providers, and /or Generator Owners within thirty (30) days upon written request the information on anticipated islands derived from each Planning Coordinator's system studies as determined by Requirement R1 and /or real time power flow data pertinent to requirements for aggregating

				UFLS programs and/or providing for compensatory load shedding.
R4	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to implement an automatic UFLS program reflecting normal operating conditions excluding outages, for its Facilities or collectively implemented by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on frequency thresholds, total nominal operating time, and amounts specified in the appropriate included tables.
R5	N/A	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4, as applicable depending on their total peak net Load, butdid not inform the Planning Coordinator of the need to exceed the stated tolerances of UFLS Table 2 or Table 3, and in the case of Table 2 only, the need to deviate from	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4, as applicable depending on their total peak net Load, but did not provide the Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution	The Distribution Provider or Transmission Owner did not arm its load to trip on underfrequency in order to meet its minimum obligations and in doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4, as applicable depending on their total peak net Load.

		providing two stages of UFLS.	Provider or Transmission Owner to comply with the appropriate table.	
R6	N/A	N/A	The Distribution Provider or Transmission Owner in the Eastern Interconnection portion of NPCC with peak net Load connected to its Facilities shall ensure that the total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time, but did not measure the underfrequency relay operating time from the time the frequency passes through the frequency threshold set point, using a test rate of linear frequency decay of 0.2 Hz per second, OR the measurement and any subsequent testing of the UFLS relays did not utilize a test rate of linear frequency decay of 0.2 Hz per second if the relay operating times is dependent on the rate of frequency decay.	The Distribution Provider or Transmission Owner in the Eastern Interconnection portion of NPCC with peak net Load connected to its Facilities did not ensure that the total nominal operating time included the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time.

R7	N/A	N/A	N/A	The Distribution Provider or Transmission Owner did not implement an automatic UFLS program for its facilities, or did not implement collectively by the mutual agreement with one or more Distribution Providers and Transmission Owners within the same island an aggregated automatic UFLS program based on the frequency thresholds, slopes, total nominal operating time, and the amounts shown in the table.
R8	N/A	N/A	N/A	The Distribution Provider or Transmission Owner did not ensure that total nominal operating time included the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time, or the underfrequency relay operating time was not measured from the time when the frequency passes through the frequency threshold set point.
R9	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to set their underfrequency relays with the minimum time delay requirement.
R10	N/A	N/A	N/A	The Planning Coordinator failed to develop, implement, and maintain a program to establish the appropriate voltage inhibit

				threshold to be used within its region's UFLS program.
R11	N/A	N/A	N/A	The Planning Coordinator failed to provide to Transmission Owners and Distribution Providers within its program area the specific inhibit thresholds applicable to each Transmission Owner or Distribution Provider within thirty (30) days of the initial determination of the required inhibit threshold settings or for changes to those settings.
R12	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R11.
R13	N/A	N/A	N/A	The Distribution Provider or Transmission Owner shall develop and submit an implementation plan within ninety (90) days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R11.
R14	The Transmission Owner or Distribution Provider exceeded the annual documentation	The Transmission Owner or Distribution Provider exceeded the annual documentation	The Transmission Owner or Distribution Provider exceeded the annual documentation submission	The Transmission Owner or Distribution Provider did not provide documentation to its

	submission to its Planning Coordinator by up to thirty (30) days, OR exceeded by up to thirty (30) the fifteen (15) months between updates provided to its Planning Coordinator of the actual net load that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year.	submission to its Planning Coordinator by up to sixty (60) days, OR exceeded by up to sixty (60) days the fifteen (15) months between updates provided to its Planning Coordinator of the actual net load that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year.	to its Planning Coordinator by up to ninety (90) days, OR exceeded by up to ninety (90) the fifteen (15) months between updates provided to its Planning Coordinator of the actual net load that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year.	Planning Coordinator of actual net load data or updates to the data that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year.
R15	N/A	N/A	N/A	The Generator Owner failed to ensure that its generating units do not trip for underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve unless exempted.
R16	N/A	N/A	N/A	The Generator Owner did not transmit the generator underfrequency trip setting and time constant to its Planning Coordinator within forty-five (45) days of the Planning Coordinator’s request.
R17	N/A	N/A	The Generator Owner did not transmit the generator underfrequency trip setting and time setting to the Planning	The Generator Owner failed to design auxiliary systems or devices used for the control and protection of auxiliary systems

			Coordinator.	necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve.
R18	N/A	N/A	N/A	The Generator Owner of existing non-nuclear units in service prior to the effective date of this standard, and which have underfrequency tripping set to trip above the curve, did not set the underfrequency protection to operate at the lowest frequency possible as demonstrated by the plant design and licensing limitations, OR did not transmit the initial underfrequency settings and any changes to the underfrequency setting s and the technical basis for those settings to the Planning Coordinator. OR did not have compensatory load shedding that was adequate to compensate for the loss of their generator due to early tripping.
R19	N/A	N/A	N/A	The Planning Coordinator did not apply the methodology described in Attachment A to determine the compensatory load shedding that is required.
R20	N/A	N/A	N/A	The Generator Owner, Distribution Provider, or

				Transmission Owner did not apply the methodology described in Attachment B to determine the compensatory load shedding that is required.
R21	N/A	N/A	N/A	The Generator Owner of existing boiling water nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve based on their licensing design basis did not set the protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations, but not greater than 57.8Hz., OR reduce the frequency trip setting tolerance on those units with threshold setting tolerances greater than +0.1Hz., OR did not transmit the initial frequency trip settings or any changes to the settings to the Planning Coordinator.
R22	The Transmission Owner or Distribution Provider exceeded the annual documentation submission to its Planning Coordinator by up to thirty (30) days, OR exceeded by up to thirty (30) days the fifteen (15) months between updates provided to its Planning Coordinator of UFLS program data.	The Transmission Owner or Distribution Provider exceeded the annual documentation submission to its Planning Coordinator by up to sixty (60) days, OR exceeded by up to sixty (60) days the fifteen (15) months between updates provided to its Planning Coordinator of UFLS program	The Transmission Owner or Distribution Provider exceeded the annual documentation submission to its Planning Coordinator by up to ninety (90) days, OR exceeded by up to ninety (90) days the fifteen (15) months between updates provided to its Planning Coordinator of UFLS program data.	The Transmission Owner or Distribution Provider did not provide its UFLS program data or updates to its Planning Coordinator.

		data.		
R23	The Planning Coordinator did not update its UFLS program data base within four months of receiving the requisite information, or did not have data for one of the parameters listed in 23.1 through 23.5.	The Planning Coordinator did not update its UFLS program data base within four months of receiving the requisite information, or did not have data for two of the parameters listed in 23.1 through 23.5.	The Planning Coordinator did not update its UFLS program data base within four months of receiving the requisite information, or did not have data for three of the parameters listed in 23.1 through 23.5	The Planning Coordinator did not develop or maintain its UFLS program data base.
R24	N/A	N/A	N/A	The Planning Coordinator did not assess that the NPCC UFLS program requirements within its Planning Coordinator area are satisfied as implemented by Transmission Owners, Distribution Providers, and Generator Owners.
R25	N/A	N/A	N/A	The Planning Coordinator did not notify its Distribution Providers, Transmission Owners, and Generator Owners of changes to load distribution needed to satisfy UFLS program requirements.
R26	N/A	N/A	N/A	The Distribution Provider, Transmission Owner, or Generator Owner did not implement the load distribution changes based on the notification provided by the Planning Coordinator.
R27	N/A	N/A	The Distribution Provider, Transmission Owner, or Generator Owner did not submit an implementation plan within ninety (90) days of the request from the	The Distribution Provider, Transmission Owner, or Generator Owner did not develop an implementation plan at the request of the Planning

			Planning Coordinator.	Coordinator.

PRC-006-NPCC-1 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with under frequency protections set to trip above the appropriate curve in Figure 1. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all islands identified in Requirement R1 in which the unit may operate.

The methodology below provides a set of criteria for the Planning Coordinator to follow for determining compensatory load shedding requirements:

1. The Planning Coordinator shall identify, compile and maintain an updated list of all existing non-nuclear generating units in service prior to the effective date of this standard that have under frequency protections set to trip above the appropriate curve in Figure 1. The list shall include the following information for each unit:

    1.1 Generator name and generating capacity
    1.2 Under frequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 All islands within which the unit may operate, as identified in Requirement R1

2. For each generating unit identified in (1) above, the Planning Coordinator shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator in Requirement R1 within which the generator may operate to provide compensatory load shedding.

    2.2 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4..

    2.3 The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 during an underfrequency event. If the highest

frequency at which the subject generator will trip above the appropriate curve in Figure 1 does not correspond to a specific UFLS program stage threshold setting, the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1.

2.4 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment B

Compensatory Load Shedding Criteria for ISO-NE and NYISO:

The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 1 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements:

1. The Generator Owner shall identify and compile a list of all existing non-nuclear generating units in service prior to the effective date of this standard that has under frequency protection set to trip above the appropriate curve in Figure 1. The list shall include the following information associated with each unit:

   1.1 Generator name and generating capacity
   1.2 Under frequency protection trip settings, including frequency trip set points and time delays
   1.3 Physical and electrical location of the unit
   1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.

2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:

   2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 1, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

   2.2 In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 1, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

   2.3 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution

Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.4 The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip.

2.5The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

Consideration of Comments on PRC-006-NPCC-1 – Frequency Load Shedding

The Regional Reliability Standard PRC-006-NPCC-1 Frequency Load Shedding Drafting Team thanks all commenters who submitted comments on the first posting of the PRC-006-NPCC-1—Automatic Under frequency Load Shedding. These standards were posted for a 45-day public comment period from January 11, 2010 through February 24, 2011. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 11 sets of comments, including comments 29 different people from approximately 22 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/regional_standards/regional_reliability_standards_under_development.html

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	Mike Garton	Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michael Gildea	Dominion Resources Services, Inc.	MRO	5
2.	Louis Slade	Dominion Resources Services, Inc.	SERC	5
3.	Connie Lowe	Dominion Resources Services, Inc.	RFC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Greg Vassallo	BPA, Transmission Customer Service Engineering	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Pat Hervochon	Public Service Enterprise Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kenneth Brown	PSE&G	RFC	1, 3
2.	Dominick Grasso	PSEG Fossil	RFC	5
3.	Peter Dolan	PSEG ER&T	RFC	6

4.	Scott Slickers	PSEG Power NY	NPCC	5
5.	Eric Schmidt	PSEG ER&T	NPCC	6
6.	Clint Bogan	Odessa Power Partners	ERCOT	5
7.	Steven Kimmish	PSEG ER&T	ERCOT	

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
4.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	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	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	FPUA	FRCC	4
7.	Randy Hahn	Ocala Electric Utility	FRCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Individual	Cynthia S. Bogorad	Transmission Access Policy Study Group	X		X	X	X	X				
6.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
7.	Individual	J. S. Stonecipher	City of Jacxksonville Beach dba/Beaches Energy Services	X								X	
8.	Individual	Dan Rochester	Independent Electricity System Operator		X								
9.	Individual	Don Weaver	New Brunswick System Operator		X								
10.	Individual	Rex Roehl	Indeck Energy Services					X					
11.	Individual	Brian Evans-Mongeon	Utility Services Inc.								X		

1. **Was the proposed standard developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?**

Summary Consideration:

Organization	Yes or No	Question 1 Comment
Dominion Electric Market Policy	No	PRC-006-NPCC-1 was filed concurrently at NPCC and NERC. However, the ballot for this standard has not yet passed at NPCC. Accordingly, this standard is not ripe for NERC consideration. Dominion suggests that NERC suspend this proceeding until the ballot passes at NPCC, and then reopen this proceeding for further comments based on the standard as finally approved by NPCC.
Response: Thank you for your comment. As noted in the NERC Regional Reliability Evaluation Procedure the region may request that NERC consideration of the standard occur concurrent with the anticipated final public comment period in the regional entity's regional standard development process. http://www.nerc.com/docs/sac/rrswg/NERC_Regional_Reliability_Evaluation_Procedure.pdf		
Bonneville Power Administration	Yes	
Transmission Access Policy Study Group	Yes	
Public Service Enterprise Group		As the NPCC process is still ongoing, it is difficult to develop an opinion at this time whether that process was fair and open.
Response: Thank you for your comment. As noted in the NERC Regional Reliability Evaluation Procedure the region may request that NERC consideration of the standard occur concurrent with the anticipated final public comment period in the regional entity's regional standard development process. http://www.nerc.com/docs/sac/rrswg/NERC_Regional_Reliability_Evaluation_Procedure.pdf		
Florida Municipal Power Agency		The NPCC process is still ongoing, but it is our understanding that so far it has been fair and open.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment.		
Northeast Utilities	Yes	
City of Jacksonville Beach dba/Beaches Energy Services	Yes	Yes, This is pretty much what we're doing now with some good success.
Response: Thank you for the comment.		
Independent Electricity System Operator	Yes	
New Brunswick System Operator	Yes	
Indeck Energy Services	No	1) None of our generating plants is a member of NPCC. One of them is not large enough to register for NERC membership and is connected at 34 kV. The pre-ballot review of the regional standard was not posted for public comment. No comment form is available on the public NPCC website. The letter announcing a webinar on 1/4/2011 was dated 1/6/2011. The letter also announced an extension of the comment period from the date of the letter to a week later. The process is patently unfair to generators or others in NPCC that are not members. 2) The standard improperly extends NERC standards to non-registered entities. NPCC's authority to implement regional reliability standards issues from its delegation agreement with NERC. NERC has chosen not to extend registration to entities <20 MW or not connected to the BES.
Response: Thank you for your comment. **1) According to the NPCC Regional Standards Development Procedure the pre ballot review is not intended for comment. Additionally, the NPCC bylaws promote membership for all registered entities which allow members to actively participate in the development of regional standards.** **2)The Regional Standard Drafting Team has reviewed your concerns and notes that the NERC Statement of Registry Criteria does not limit registration of generation to those greater than 20MVA. However, the applicability in Section 4 has been revised and Attachment C has been removed.**		

Organization	Yes or No	Question 1 Comment
Utility Services Inc.	Yes	

2. **Does the proposed standard pose an adverse impact to reliability or commerce in a neighboring region or interconnection?**

Summary Consideration:

Organization	Yes or No	Question 2 Comment
Dominion Electric Market Policy	Yes	See comments (item #1) below under Question 5.
Response: Thank you for your comment. Please see the response developed for item#1 Question 5.		
Bonneville Power Administration	No	
Public Service Enterprise Group		No Comment
Florida Municipal Power Agency	Yes	FMPA questions the need for the proposed regional standard. A continent-wide UFLS standard has been drafted and approved by stakeholders and the NERC Board, and will presumably be filed at FERC in the very near future. That standard is sufficient to protect reliability; the industry should not, at this point in time, be devoting its scarce resources to developing regional standards on the same subject. Reliability Standard PRC-006-1 requires Planning Coordinators to develop UFLS programs. It does not require Regional Entities to develop separate reliability standards. Furthermore, a regional standard on this topic could place the entities in NPCC under a double jeopardy threat since all the entities will need to comply with mandatory NERC and Regional Standards. This double jeopardy threat is exacerbated by the fact that the continent-wide standard requires a periodic review and potential change to the program every five years whereas the NPCC program locks the UFLS relay settings into a regional standard that cannot be changed without FERC approval. If those relay settings need to be changed pursuant to the continent-wide standard, there would be a conflict between the continent-wide standard and the regional standard that could only be resolved through a revision to one of the standards, which would have to be FERC-approved to go into effect. In the meantime, entities would have no choice but to be non-compliant with one of the two standards. NPCC would be better served by being consistent with

Organization	Yes or No	Question 2 Comment
		NERC's PRC-006-1 and not developing a UFLS program as a regional standard. . The draft regional standard's proposed applicability to Generator Owners--including to small, otherwise unregisterable generators--highlights the proposed framework's inappropriateness in the context of continent-wide standards. NERC's PRC-006-1 does not apply to Generator Owners because the frequency protection set points are being covered in PRC-024-1, which is currently with its SDT. Covering generators in a regional PRC-006 will result in confusion and a lack of coordination, including the risk of a conflict between the regional standard and PRC-024-1. If NPCC proceeds down a path of developing a regional standard, at a minimum, applicability to generators should be removed altogether. Furthermore, the proposed NPCC UFLS program is not robust enough to serve the overall reliability of the Eastern Interconnect. The NPCC UFLS program seems to be designed such that a 1% inaccuracy causes the UFLS program to no longer meet performance requirements. This is far too tight of a tolerance for an inherently inaccurate analysis and reflects a lack of robustness of the UFLS program. The Eastern Interconnect would be better protected from an event that causes multiple region instability by a more robust UFLS program.It seems that one of the primary drivers in designing NPCC's UFLS program is to cover the Connecticut island, with roughly 6000 MW of peak load. The SS-38 report titled "Determination of a Threshold for Generator Applicability" dated November 15, 2010 shows in its Table 1 on Page 3 that there is only a 1% margin of error in the supply / demand mismatch in the design of the program (or 60 MW).There are numerous sources of inaccuracy of greater than 1% in the analysis and design of a UFLS program. Hence, since the proposed UFLS program cannot tolerate a 1% error, it is insufficiently robust to protect reliability. A UFLS program more robust than that proposed in this regional reliability standard would benefit other regions in the Eastern Interconnect by helping to defray opportunity for cascading from one region to another.Examples of sources of inaccuracy greater than 1% include: 1. Load models are nowhere close to 1% accurate. As an industry, we are unavoidably uncertain of the extent to which electronic and power electronic equipment such as variable speed drives, compact fluorescent lighting, etc., have penetrated customer premises; we cannot know this because we cannot

Organization	Yes or No	Question 2 Comment
		control customer behavior. In addition, we can only approximate how these devices interact with voltage and frequency excursions. An inaccurate load model showing that load decreases less by voltage than actual, for instance, could result in post-disturbance conditions with a far greater than 1% supply/demand mismatch, outside the NPCC design tolerance. If post-disturbance load is actually 60 MW more than modeled, that disparity has the same impact as tripping an additional 60 MW of generation. 2. UFLS relays are typically on individual distribution feeders, each of which have different load profiles, different distributed generation patterns, different levels of important load such as hospitals, and different levels of electronic and power electronic loads, and are in other ways dissimilar to each other and to the overall system load pattern. Hence, load diversity with respect to time of day, day of week, time of season, amount of distributed generation (e.g., generator assistance programs, net-metering and feed-in tariffs), priority of loads, composition of loads, etc., will result in a larger than 1% inaccuracy in the amount of load tripped by the UFLS program. If 60 MW too little load is shed, it has the same impact as tripping an additional 60 MW of generation. 3. The continent-wide PRC-006-1 recently approved by the BOT contains a reasonable, but arbitrary assumption of a 25% supply / demand mismatch. The fact that the NERC standard had to choose a relatively arbitrary number shows the inexactness of the science of designing a UFLS program. This inexactness runs counter to a philosophy of designing a UFLS program with only a 1% margin of error; such a UFLS program lacks the robustness of larger design tolerances. 4. Many more examples exist of inaccuracies inherent in stability studies and UFLS program design greater than 1%, such as: a) governing systems are difficult and risky to test and their performance characteristic changes with different operating conditions such as temperature, pressure and power level; and b) the partial differential equations and numerical methods that describe the stability response of the system are subject to what mathematicians call “Chaos Theory” and cannot be accurate to within 1%.NPCC mistakenly believes that a 1% design tolerance can be achieved and uses this mistaken belief to include very small generators in its UFLS program. As shown above, a 1% design tolerance cannot be achieved due to the very nature of

Organization	Yes or No	Question 2 Comment
		variable load and other variables that cannot be modeled to within a 1% margin of error.The correct approach is to determine the range of error inherent in the variables used in performing UFLS program design. If a variable cannot be modeled to within a +/-10% accuracy bandwidth (as is likely the case of loads and load models), the UFLS program should be designed to be robust enough to tolerate this margin of error. By not designing the UFLS program with more reasonable design tolerances, the NPCC program creates unnecessary risk to the reliability of the Eastern Interconnect.
Response: Thank you for your comment. The standard was developed in response to a request from NERC to satisfy FERC Order 693 issued in 2006. At that time, twenty four standards were identified as "fill in the blank" and as a result the FERC directed NERC to modify the individual standards reliance on the Regional Reliability Organization. **Additionally, of those twenty four standards, four were identified by NERC and the regions to be regionally specific enough to warrant the development of a regional standard and Under Frequency Load Shedding is one of those four standards.** **The remaining comments are beyond the scope of Question#2.**		
Transmission Access Policy Study Group	Yes	TAPS questions the need for the proposed regional standard. A continent-wide UFLS standard has been drafted and approved by stakeholders and the NERC Board, and will presumably be filed at FERC in the very near future. That standard is sufficient to protect reliability; the industry should not, at this point in time, be devoting its scarce resources to developing regional standards on the same subject. Reliability Standard PRC-006-1 requires Planning Coordinators to develop UFLS programs. It does not require Regional Entities to develop separate UFLS reliability standards.Furthermore, a regional standard on this topic could place the entities in NPCC under a double jeopardy threat since all the entities will need to comply with mandatory NERC and Regional Standards. This double jeopardy threat is exacerbated by the fact that the continent-wide standard requires a periodic review and potential change to the program every five years whereas the NPCC program locks the UFLS relay settings into a regional standard that cannot be changed without FERC approval. If those relay settings need to be changed pursuant to the continent-wide standard, there would be a conflict between the continent-wide standard and the regional standard that could only be resolved through a revision to one of the standards, which would have to be FERC-approved to go into effect. In the meantime, entities would have no choice but to be non-compliant with one of the two standards. NPCC would be better served by being consistent with NERC's PRC-006-1 and not developing a UFLS program as a regional standard. The draft regional standard's proposed applicability to Generator Owners--including to small, otherwise unregisterable generators--highlights the proposed framework's inappropriateness in the context of continent-wide standards. NERC's PRC-006-1 does not apply to Generator Owners because the

Organization	Yes or No	Question 2 Comment
		frequency protection set points are being covered in PRC-024-1, which is currently with its SDT. Covering generators in a regional PRC-006 will result in confusion and a lack of coordination, including the risk of a conflict between the regional standard and PRC-024-1. If NPCC proceeds down a path of developing a regional standard, at a minimum, applicability to generators should be removed altogether.Furthermore, the proposed NPCC UFLS program is not robust enough to serve the overall reliability of the Eastern Interconnect. The NPCC UFLS program seems to be designed such that a 1% inaccuracy causes the UFLS program to no longer meet performance requirements. This is far too tight of a tolerance for an inherently inaccurate analysis and reflects a lack of robustness of the UFLS program. The Eastern Interconnect would be better protected from an event that causes multiple region instability by a more robust UFLS program.It seems that one of the primary drivers in designing NPCC's UFLS program is to cover the Connecticut island, with roughly 6000 MW of peak load. The SS-38 report titled "Determination of a Threshold for Generator Applicability" dated November 15, 2010 shows in its Table 1 on Page 3 that there is only a 1% margin of error in the supply / demand mismatch in the design of the program (or 60 MW).There are numerous sources of inaccuracy of greater than 1% in the analysis and design of a UFLS program. Hence, since the proposed UFLS program cannot tolerate a 1% error, it is insufficiently robust to protect reliability. A UFLS program more robust than that proposed in this regional reliability standard would benefit other regions in the Eastern Interconnect by helping to defray opportunity for cascading from one region to another.Examples of sources of inaccuracy greater than 1% include:1. Load models are nowhere close to 1% accurate. As an industry, we are unavoidably uncertain of the extent to which electronic and power electronic equipment such as variable speed drives, compact fluorescent lighting, etc., have penetrated customer premises; we cannot know this because we cannot control customer behavior. In addition, we can only approximate how these devices interact with voltage and frequency excursions. An inaccurate load model showing that load decreases less by voltage than actual, for instance, could result in post-disturbance conditions with a far greater than 1% supply/demand mismatch, outside the NPCC design tolerance. If post-disturbance load is actually 60 MW more than modeled, that disparity has the same impact as tripping an additional 60 MW of generation.2. UFLS relays are typically on individual distribution feeders, each of which have different load profiles, different distributed generation patterns, different levels of important load such as hospitals, and different levels of electronic and power electronic loads, and are in other ways dissimilar to each other and to the overall system load pattern. Hence, load diversity with respect to time of day, day of week, time of season, amount of distributed generation (e.g., generator assistance programs, net-metering and feed-in tariffs), priority of loads, composition of loads, etc., will result in a larger than 1% inaccuracy in the amount of load tripped by the UFLS program. If 60 MW too little load is shed, it has the same impact as tripping an additional 60 MW of generation.3. The continent-wide PRC-006-1 recently approved by the BOT contains a reasonable, but arbitrary assumption of a 25% supply / demand mismatch. The fact that the NERC standard had to choose a relatively arbitrary number shows the inexactness of the science of designing a UFLS program. This inexactness runs counter to a philosophy of designing a UFLS program with only a 1% margin of error; such a UFLS program lacks the robustness of larger design tolerances.4. Many more examples exist of inaccuracies

Organization	Yes or No	Question 2 Comment
		inherent in stability studies and UFLS program design greater than 1%, such as: a) governing systems are difficult and risky to test and their performance characteristic changes with different operating conditions such as temperature, pressure and power level; and b) the partial differential equations and numerical methods that describe the stability response of the system are subject to what mathematicians call "Chaos Theory" and cannot be accurate to within 1%.NPCC mistakenly believes that a 1% design tolerance can be achieved and uses this mistaken belief to include very small generators in its UFLS program. As shown above, a 1% design tolerance cannot be achieved due to the very nature of variable load and other variables that cannot be modeled to within a 1% margin of error.The correct approach is to determine the range of error inherent in the variables used in performing UFLS program design. If a variable cannot be modeled to within a +/-10% accuracy bandwidth (as is likely the case with respect to loads and load models), the UFLS program should be designed to be robust enough to tolerate this margin of error. By not designing the UFLS program with more reasonable design tolerances, the NPCC program creates unnecessary risk to the reliability of the Eastern Interconnect.
Response: Thank you for your comment. The standard was developed in response to a request from NERC to satisfy FERC Order 693 issued in 2006. At that time, twenty four standards were identified as "fill in the blank" and as a result the FERC directed NERC to modify the individual standards reliance on the Regional Reliability Organization. Additionally, of those twenty four standards, four were identified by NERC and the regions to be regionally specific enough to warrant the development of a regional standard and Under Frequency Load Shedding was one of those four standards. The remaining comments are beyond the scope of Question#2.		
Northeast Utilities	No	
City of Jacxksonville Beach dba/Beaches Energy Services	No	
Independent Electricity System Operator	No	
New Brunswick System Operator	No	

Organization	Yes or No	Question 2 Comment
Indeck Energy Services		
Utility Services Inc.	Yes	The standard's incorporation of generation that is unregistered in the ERO Compliance activities will adversely impact reliability. The standard proposes to include generation between 1 MVA and the registration criteria. Without a thorough examination of the impacts of this generation to the compliance, it is unknown how these "new" registered entities will be dealt with. Further, the standard's requirements in certain ways is inconsistent with the underlying study that is the basis for the UFLS program. The standard requires differing curtailment requirements for load versus load being shed for compensatory generation that is above the curve. Reported data is based upon non-coincidentalized readings while the study is predicated upon coincidentalized meter readings. The standards expose Registered Entities to double jeopardy when there is a violation. Compensatory loadshedding can be difficult to achieve when there are no willing players and the objective creates financial incentives to entities to withhold from negotiations.

Response: Thank you for response. The applicability in Section 4 has been revised and Attachment C has been removed.

Additionally, the SS-38 study represents the initial baseline for the Under Frequency program within NPCC. Each PC shall conduct and document a UFLS design assessment that determines through dynamic simulation whether the UFLS program meets the minimum performance characteristics as defined in the continent wide draft PRC-006.

3. **Does the proposed standard pose a serious and substantial threat to public health, safety, welfare, or national security?**

Summary Consideration:

Organization	Yes or No	Question 3 Comment
Electric Market Policy	No	
Bonneville Power Administration	No	Not that we are aware of. **Response: Thank you for your comment.**
Transmission Access Policy Study Group	No	
Public Service Enterprise Group		
Florida Municipal Power Agency		
Northeast Utilities	No	
City of Jacxksonville Beach dba/Beaches Energy Services	No	
Independent Electricity System Operator	No	
New Brunswick System Operator	No	
Indeck Energy Services	Yes	It proposes to drop 50% of load in some islanded areas at frequencies above 58 hz. If they are islanded, they are no longer a risk to reliability of the system. These islanded areas may be subsidizing the larger areas at great cost and potential safety risk to these customers.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your response. The results of studies conducted by the NPCC SS38 technical committee showed that the current frequency response for the islands tested are similar to the responses obtained in Part III of the 2006 UFLS Assessment. Thus the variances proposed by the Regional Standard Drafting Team (RSDT) for the small load serving entities are acceptable according to the current levels of load served by such entities on the NPCC system. **SS-38 observed that the draft NPCC standard did not specify an upper limit on the amount of load to be armed for UFLS for LSE's in Table 2 and 3 of the draft standard.** **SS-38 feels that a cumulative upper limit of 50% would keep the amount of load armed for UFLS by these LSE's (i.e. 50% at the first stage for Table #3 and 25% each at the first and third stages for Table #2) closer to the original program design while providing latitude to accommodate any constraints due to the granularity of loads on a limited numbers of feeders.** **The data submitted for each Area showed that the amount of load in each of the small LSE categories to be small percentages of the overall peak load for current day system conditions. It is recognized that these upper limits may require revision if system conditions change and more LSEs are classified.**		
Utility Services Inc.	No	

4. Does the proposed standard pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?

Summary Consideration:

Organization	Yes or No	Question 4 Comment
Electric Market Policy	No	
Bonneville Power Administration	No	
Public Service Enterprise Group	No	
Transmission Access Policy Study Group	Yes	In requirement R17, the standard would force generators that do not meet the performance requirements in the standard (non-conforming generators) to either: 1) make substantial investments to meet performance requirements imposed on them after they are already interconnected and in commercial operation, or 2) enter an agreement for compensatory load shedding with one of a limited number of entities that can offer such service, and with no market to inform pricing of such service. Either option is a significant burden on the competitiveness of these generators which results in a substantial burden on competitive markets. Also, as discussed in response to Question 2, the 1% design tolerance desired by the NPCC UFLS program design team is a flaw in the design itself; hence, with a more reasonable design tolerance, there is no reliability reason to place this unreasonable burden on small generators. Compensatory load shedding should NOT be allowed for two reasons: 1) the standards should not force agreements to be made; and 2) the UFLS program would become a highly complex scheme with settings that would need to change over time to reflect the status of the non-conforming generator, e.g., if the unit were off-line, then too much load would be "armed" to trip, so, those relay settings would need to be changed when the unit was offline.The complexity of a UFLS program that would have to track the status of non-conforming generators is staggering. For instance, in order to protect the 1% design tolerance of supply / demand balance that the drafters of the standard mistakenly believe is important, the UFLS relay settings would need to change every time the generator changed output. For instance, a non-conforming generator with a capacity of 300 MW would presumably have 300 MW of compensatory load shedding. If it were running at 200 MW, then we would want the 300 MW of compensatory load shedding dropped to 200 MW. How would such a

Organization	Yes or No	Question 4 Comment
		thing be possible if we are limited to a finite level of distribution circuits whose load varies minute to minute with different load patterns, with varying levels of critical loads (e.g., hospitals) and non-critical loads on those circuits? At what UFLS steps would the compensatory load shedding be adjusted? Would it be multiple steps? If the generator were providing regulation service, the relay settings would need to change minute by minute on different circuits depending on actual loads on those circuits. If the ability to make such minute-by-minute relay changes were not in place, would the generator be barred from participating in the regulation service ancillary services market, further burdening competitive markets? Compensatory load shedding is ill-conceived and highly impractical.The NERC-wide standard recently approved by the BOT takes the correct approach. Existing non-conforming generators of a sufficient size to matter should be modeled and the UFLS program be designed in a robust enough fashion to handle the non-conforming generation.
Response: Thank you for your comment. The RSDT acknowledges the technical challenges of administering the compensatory load shedding program and as a result has developed requirements stating that all new units shall conform to the generator tripping curve. **Additionally, to address your concern regarding generators that are already interconnected and in commercial operation, non conforming generators either have existing contracts to provide for compensatory load shedding or have mitigated the conditions that would trip the unit above the appropriate generator tripping curve.** **These, requirements are contained as criteria within the approved NPCC Directory #12 and are currently in effect throughout the NPCC region.** **Finally, the NPCC technical committee (SS38) developed reviewed and confirmed the use of tolerances as described in the standard. These studies were reviewed and approved by the NPCC Task Force on System Studies (TFSS) and the Reliability Coordinating Committee (RCC).**		
Florida Municipal Power Agency	Yes	In requirement R17, the standard would force generators that do not meet the performance requirements in the standard (non-conforming generators) to either: 1) make substantial investments to meet performance requirements imposed on them after they are already interconnected and in commercial operation, or 2) enter an agreement for compensatory load shedding with one of a limited number of entities that can offer such service, and with no market to inform pricing of such service. Either option is a significant burden on the competitiveness of these generators which results in a substantial burden on competitive markets. Also, as discussed in response to Question 2, the 1% design tolerance desired by the NPCC UFLS program

Organization	Yes or No	Question 4 Comment
		design team is a flaw in the design itself; hence, with a more reasonable design tolerance, there is no reliability reason to place this unreasonable burden on small generators.Compensatory load shedding should NOT be allowed for two reasons: 1) the standards should not force agreements to be made; and 2) the UFLS program would become a highly complex scheme with settings that would need to change over time to reflect the status of the non-conforming generator; e.g., if the unit were off-line, then too much load would be "armed" to trip, so, those relay settings would need to be changed when the unit was off-line.The complexity of a UFLS program that would have to track the status of non-conforming generators is staggering. For instance, in order to protect the 1% design tolerance of supply / demand balance that the drafters of the standard mistakenly believe is important, the UFLS relay settings would need to change every time the generator changed output. For instance, a non-conforming generator with a capacity of 300 MW would presumably have 300 MW of compensatory load shedding. If it were running at 200 MW, then we would want the 300 MW of compensatory load shedding dropped to 200 MW. How would such a thing be possible if we are limited to a finite level of distribution circuits whose load varies minute to minute with different load patterns, with varying levels of critical loads (e.g., hospitals) and non-critical loads on those circuits? At what UFLS steps would the compensatory load shedding be adjusted? Would it be multiple steps? If the generator were providing regulation service, the relay settings would need to change minute by minute on different circuits depending on actual loads on those circuits. If the ability to make such minute-by-minute relay changes were not in place, would the generator be barred from participating in the regulation service ancillary services market, further burdening competitive markets? Compensatory load shedding is ill-conceived and highly impractical.The NERC-wide standard recently approved by the BOT takes the correct approach. Existing non-conforming generators of a sufficient size to matter should be modeled and the UFLS program be designed in a robust enough fashion to handle the non-conforming generation.

Response: Thank you for your comment. The RSDT acknowledges the technical challenges of administering the compensatory load shedding program and as a result has developed requirements stating that all new units shall conform to the generator tripping curve.

Additionally, to address your concern regarding generators that are already interconnected and in commercial operation, non conforming generators either have existing contracts to provide for compensatory load shedding or have mitigated the conditions that would trip the unit above the appropriate generator tripping curve.

These requirements are contained as criteria within the approved NPCC Directory #12 and are currently in effect throughout the NPCC region.

Organization	Yes or No	Question 4 Comment
Finally, the NPCC technical committee (SS38) developed reviewed and confirmed the use of tolerances as described in the standard. These studies were reviewed and approved by the NPCC Task Force on System Studies (TFSS) and the Reliability Coordinating Committee (RCC).		
Northeast Utilities	No	
City of Jacxksonville Beach dba/Beaches Energy Services	No	
Independent Electricity System Operator	No	
New Brunswick System Operator	No	
Indeck Energy Services	Yes	The standard imposed a significant burden on the customers of DP's and TO's with less than 100 MW of load by requiring substantially higher percentages of load reductions at similar frequencies. In addition, this standard is not necessary for reliability because, and is particularly burdensome, the DP's and TO's with less than 100 MW's of load are each too small to be a Reportable Disturbance within either the NYISO or ISONE. How then is reliability improved? Also, the standard improperly extends its applicability to GO's less than 20 MW and not connected to directly to the BES. NPCC is delegated its power to develop Regional Standards under the delegation agreement with NERC. NERC has chosen not to apply its standards to any entities other than Registered Entities. Therefore, NPCC may not apply the standard to GO's that are not Registered Entities. The publicly available information does not justify the differences from continent wide standard compared to the burden on competitive markets.
Response: Thank you for your comment. Entities with less than 100MWs are provided additional flexibility via wider cumulative load shedding bands. This allowance, supported by technical studies, was provided based on evidence that many smaller entities could not provide the necessary load shedding without exceeding their requirement based on their limited number of feeders available to be armed. **Additionally, the minimum obligation of these entities is essentially the same of entities greater than 100MWs.**		

Organization	Yes or No	Question 4 Comment
Finally, the applicability in Section 4 has been revised and Attachment C has been removed.		
Utility Services Inc.	Yes	See answer in Q2. Generators whose protection systems trip above the curve are "required" to find load to be shed. Load could withhold such until financial incentives were offered. It is also possible that compensatory load might not be found and then the generation would be in violation of the standard. There are no guarantees of compensatory load shedding in today's competitive horizontal electric markets.
Response: Thank you for your comment. The RSDT acknowledges the technical challenges of administering the compensatory load shedding program and as a result has developed requirements stating that all new units shall conform to the generator tripping curve. **These requirements are contained as criteria within the approved NPCC Directory #12 and are currently in effect throughout the NPCC region.**		

5. Does the proposed regional reliability standard meet at least one of the following criteria?

- **The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard**
- **The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard**
- **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

Summary Consideration:

Organization	Yes or No	Question 5 Comment
Dominion Electric Market Policy	Yes	Dominion is opposed to NPCC regional reliability standard PRC-006-1, Automatic Underfrequency Load Shedding, for the following reasons:1. The process by which a Generator Owner would arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load shed (Reference Attachment B, Step 2.2) remains unresolved. In previous comments, we noted that Dominion had polled various Transmission Owners and Distribution Providers and none were willing to offer load shed service, citing the following: a. Implementation - load shed service does not currently exist in the Transmission Owner or Distribution Providers' tariffs. Requiring them to implement this service, would raise numerous issues, including, but not limited to the issues of determining which customers' load is shed to provide this service (retail or wholesale) and in determining 'fair value' for the price of such service. Accordingly, a requirement that these entities create and manage a new service that is not compelled by the needs of the market, would have a detrimental impact on commerce. b. Technical difficulty - (design complexity, difficulty meeting overshoot requirements) - Shedding additional load equivalent to a non-coordinating generator would be extremely difficult to design and coordinate. The design would have to account for the real-time status and output of the generator. Otherwise, this requirement could create more problems than it attempts to solve. For example, consider a load shed program that is designed assuming the need to shed load equivalent to rated capacity for a non-coordinating generator and a frequency event occurs when this generator is off line. The program sees the frequency at the trigger level and sheds the load equivalent to the non-coordinating generator.

Organization	Yes or No	Question 5 Comment
		However, since that generator wasn't actually on line, there is no additional loss of generation, but the MW load equivalent of the generator (that is not designed into the UFLS scheme) is lost anyway. If the UFLS program then implements the next level of designed reduction of load, this may result in a subsequent rebound in frequency. This may very well result in overshoot that is more than designed for, resulting in generator trip from over-frequency. Obviously, the more non-coordinating generators there are, the more difficult the task of coordination with UFLS schemes becomes and the more widespread the effects on customers. c. 2. The Implementation Plan suggests that "the Drafting Team coordinated its development [of NPCC regional reliability standard PRC-006-1] with the recently approved NERC UFLS Standard PRC-006". Dominion is compelled to point out that NERC UFLS Standard PRC-006 has only attained NERC Board of Trustee approval, has not yet been approved by FERC, and is therefore not enforceable. Since there is uncertainty as to the FERC outcome, Dominion recommends that NERC suspend its review of regional reliability standard NPCC regional reliability standard PRC-006-1until continent-wide standards PRC-006 (Project 2007-01) and PRC-024 (Project 2007-09) are approved by FERC. d. 3. The applicability of this standard to "Generator Owners with individual generating units or generating plant/facility <= 1 MVA (nameplate rating) connected at all voltage levels" does not meet the NERC Statement of Compliance Registry Criteria (Revision 5.0) or the NPCC Compliance Guidance Statement "Defining Generator Materiality for Registration;" therefore creating a registration gap. Attachment "C" attempts to close this gap by requiring these facilities to coordinate with NPCC UFLS program characteristics as mandated by their respective OATT tariff agreements. This appears inappropriate in a Regional Reliability Standard as enforcement of the OATT tariff resides with FERC, not NERC or the Regions. Therefore, as acknowledged by NPPC during the January 4, 2011 Webinar, the issue of registration for generating plants/facilities <= 1 MVA, but < the NERC Registration Criteria remains unresolved.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. The RSDT acknowledges the technical challenges of administering the compensatory load shedding and as a result has developed requirements stating that all new units shall conform to the generator tripping curve. NERC has mandated the development of certain regional standards and its development cannot wait until all approvals are obtained on the NERC continent wide standard. However, the RSDT did coordinate the development of the regional standard with the progress of the continent wide standard. The Regional Standard Drafting Team has reviewed your concerns and notes that the NERC Statement of Registry Criteria does not limit registration of generation to those greater than 20MVA. However, the applicability in Section 4 has been revised and Attachment C has been removed.		
Bonneville Power Administration	Yes	
Transmission Access Policy Study Group	Yes	
Public Service Enterprise Group		
Florida Municipal Power Agency		
Northeast Utilities	Yes	
City of Jacxksonville Beach dba/Beaches Energy Services	Yes	
Independent Electricity System Operator	Yes	
New Brunswick System Operator	Yes	
Indeck Energy Services	No	

Organization	Yes or No	Question 5 Comment
Utility Services Inc.	Yes	

END OF REPORT

PRC-006-NPCC-1 Automatic Underfrequency Load Shedding

Implementation Plan

Background:

The purpose of this draft Regional Standard is to ensure the development and maintenance of an effective and coordinated Automatic Underfrequency Load Shedding program in order to preserve the reliability and integrity of the bulk power system during declining system frequency events.

In the developing the Implementation Plan for PRC-006-NPCC-01 the Standard Drafting Team considered the following:

1. The requirements listed in this Regional Standard are intended to cover all aspects of the UFLS program. The Drafting Team coordinated its development with the recently approved NERC UFLS Standard PRC-006. The intent of this Regional Standard is to be more stringent than the continent wide standard while incorporating specific program characteristics into the requirements.
2. The Implementation Plan for this standard is the same as the existing and ongoing Implementation Plan for NPCC Directory #12.
3. The Regional Standard implementation plan will not require adherence to the annual milestones within the Directory #12 plan. However, entities will be required to be fully compliant by the end of the existing Directory #12 implementation plan.

Effective Dates:

1. The effective date for requirements R1, R2, R3, R4, R5, R6, R7, and R8 is the first day of the first quarter following applicable regulatory approval but no earlier than Jan 1, 2016 to allow for the existing implementation plan to be completed.
2. The effective date for requirements R9 through R26 is the first day of the first quarter two years following applicable governmental and regulatory approval.

Reference:

- 2006 Assessment of UFLS Adequacy Part 3 Assessment of Program Modifications.
- SS38 Underfrequency Load Shedding Support Study

NPCC Criteria:

- Directory #12 Underfrequency Load Shedding Program Requirements.
- A-7 NPCC Glossary of Terms.

Implementation Plans:

- UFLS Implementation Plan for the Eastern Interconnection Portion of NPCC.
- UFLS Implementation Plan for the Québec Interconnection Portion of NPCC.

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. The Standards Committee approved the SAR for posting on November 21, 2006.
2. SAR posted for comments on November 29, 2006.
3. The Standards Committee appointed a SAR Drafting Team on January 11, 2007.
4. SAR Drafting Team responds to comments, revises SAR and posts for comments on February 7, 2007.
5. SAR Drafting Team responds to comments on April 20, 2007.
6. Standards Committee approves development of Standard on April 10, 2007.
7. The Standards Committee appointed the Standard Drafting Team on April 10, 2007.
8. The Standards Drafting Team posted draft performance characteristics for comment on July 2, 2008.
9. Standards Drafting Team responds to comments, revises standard, and posts for comments on April 15, 2009.
10. Standards Committee approved the Supplemental SAR for posting on October 7, 2009 that expanded the SDT's scope to include EOP-003-1 but limiting that scope to only eliminating references to Under-frequency Load Shedding in EOP-003-1.
11. The Standards Drafting Team posted the standard for a third comment period June 11, 2010 – July 16, 2010.
12. The Standard Drafting Team conducted a pre-ballot review of the standard on June 11, 2010 – July 2, 2010
13. The Standard Drafting Team conducted an initial ballot of the standard and non-binding poll of the VRFs and VSLs on July 8, 2010 – July 17, 2010.
14. The Standard Drafting Team conducted a second ballot of the standard on July 24, 2010 – August 3, 2010.
15. The Standard Drafting Team conducted a third ballot of the standard September 24- October 4, 2010.

Proposed Action Plan and Description of Current Draft:

This is the recirculation ballot period of the proposed standard.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Request BOT approval	November , 2010
2. File Standard with FERC	December, 2010

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**

2. **Number:** PRC-006-1

3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

4. **Applicability:**

   4.1. Planning Coordinators

   4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:

   4.2.1 Transmission Owners

   4.2.2 Distribution Providers

   4.3 Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

5. **(Proposed) Effective Date:**

   5.1. The standard, with the exception of Requirement R4, Parts 4.1 through 4.6, is effective the first day of the first calendar quarter one year after applicable regulatory approvals.

   5.2. Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1.

B. Requirements

R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

2.1. Those islands selected by applying the criteria in Requirement R1, and

2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and

2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from Regional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.

R3. Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

R4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

R5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: *[VRF: Medium][Time Horizon: Long-term Planning]*

- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.

R6. Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*

R8. Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*

R9. Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*

R10. Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*

R11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

11.1. The performance of the UFLS equipment,

11.2. The effectiveness of the UFLS program.

R12. Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

R13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those

of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

R14. Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

14.1. UFLS program, including a schedule for implementation

14.2. UFLS design assessment

14.3. Format and schedule of UFLS data submittal

C. Measures

M1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.

M2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.

M3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.

M4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.

M5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.

M6. Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per

Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.

M7. Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.

M8. Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.

M9. Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.

M10. Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application per Requirement R10.

M11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.

M12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

M13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.

M14. Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

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

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, and R14, Measures M1, M2, M3, M4, M5, M12, and M14 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.
- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking

- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

Not applicable.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. OR The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.
R2	N/A	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3. OR The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s).,but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions. OR The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area
R4	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7. OR The Planning Coordinator failed to conduct and document a UFLS

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2
R5	N/A	N/A	N/A	The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5.
R6	N/A	N/A	N/A	The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.
R7	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request. OR The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	The UFLS entity provided data to its Planning Coordinator(s) more than 5 calendar days but less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
R9	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.
R10	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application	The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission	determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission	determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission	Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission
R11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as specified in Requirement R11, Parts11.1 or 11.2.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				assessment of the event within one year of event actuation but failed to evaluate all of the Parts as specified in Requirement R11, Parts 11.1 and 11.2.
R12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies.
R13	N/A	N/A	N/A	The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, failed to coordinate its UFLS event assessment with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				described in Requirement R13
R14	N/A	N/A	N/A	The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3.

E. Regional Variances

E.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

E.A.3. Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

E.A.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.A.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.A.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

EA.3.3.1. Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES

EA.3.3.2. Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES

EA.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.

E.A.4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

E.A.4.1 Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1A, and

E.A.4.2 Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 - Attachment 2A, and

E.A.4.3 Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.E.A.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.A.3 Parts E.A.3.1 through EA3.3.

M.E.A.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement E.A.4 Parts E.A.4.1 through E.A.4.3.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
EA3	N/A	The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts E.A.3.1, E.A.3.2, and E.A.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program.
EA4	N/A	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 but simulation failed to include one (1) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include two (2) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include all of the items as specified in Parts E.A.4.1, E.A.4.2 and E.A.4.3. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3

E.B. Regional Variance for the Western Electricity Coordinating Council

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

E.B.1. Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

E.B.2. Each Planning Coordinator shall identify one or more islands from the regional review (per E.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

E.B.2.1. Those islands selected by applying the criteria in Requirement E.B.1, and

E.B.2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System.

EB.3. Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

E.B.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.B.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.B.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

E.B.3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

E.B.3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

E.B.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

E.B.4. Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

E.B.4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

E.B.4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

E.B.4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1 - Attachment 1.

E.B.4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

E.B.4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

E.B.4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1 — Attachment 1.

E.B.4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

E.B.11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

E.B.11.1. The performance of the UFLS equipment,

E.B.11.2 The effectiveness of the UFLS program

E.B.12. Each Planning Coordinator, in whose islanding event assessment (per E.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

M.E.B.1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement E.B.1.

M.E.B.2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per E.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement E.B.2 Parts E.B.2.1 and E.B.2.2.

M.E.B.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.B.3 Parts E.B.3.1 through E.B.3.3.

M.E.B.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement E.B.4 Parts E.B.4.1 through E.B.4.7.

M.E.B.11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement E.B.11.

M.E.B.12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements E.B.12 and E.B.4 if UFLS program deficiencies are identified in E.B.11.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.B.1	N/A	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands OR The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands
E.B.2	N/A	N/A	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2 OR The Planning Coordinator failed to identify any island(s) from the

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				regional review to serve as a basis for designing its UFLS program.
E.B.3	N/A	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, and E.B.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area.
E.B.4	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include one (1) of the items as specified in Requirement E.B.4, Parts E.B.4.1	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include two (2) of the items as specified in Requirement E.B.4, Parts E.B.4.1	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include three (3) of the items as specified in Requirement E.B.4, Parts E.B.4.1	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2 but the simulation failed to include four (4) or more of the items as specified in Requirement E.B.4, Parts E.B.4.1

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	through E.B.4.7.	through E.B.4.7.	through E.B.4.7.	through E.B.4.7. OR The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2
E.B.11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
			documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement E.B.11, Parts E.B.11.1 or E.B.11.2.	assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.
E.B.12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, failed to participate in and document a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies

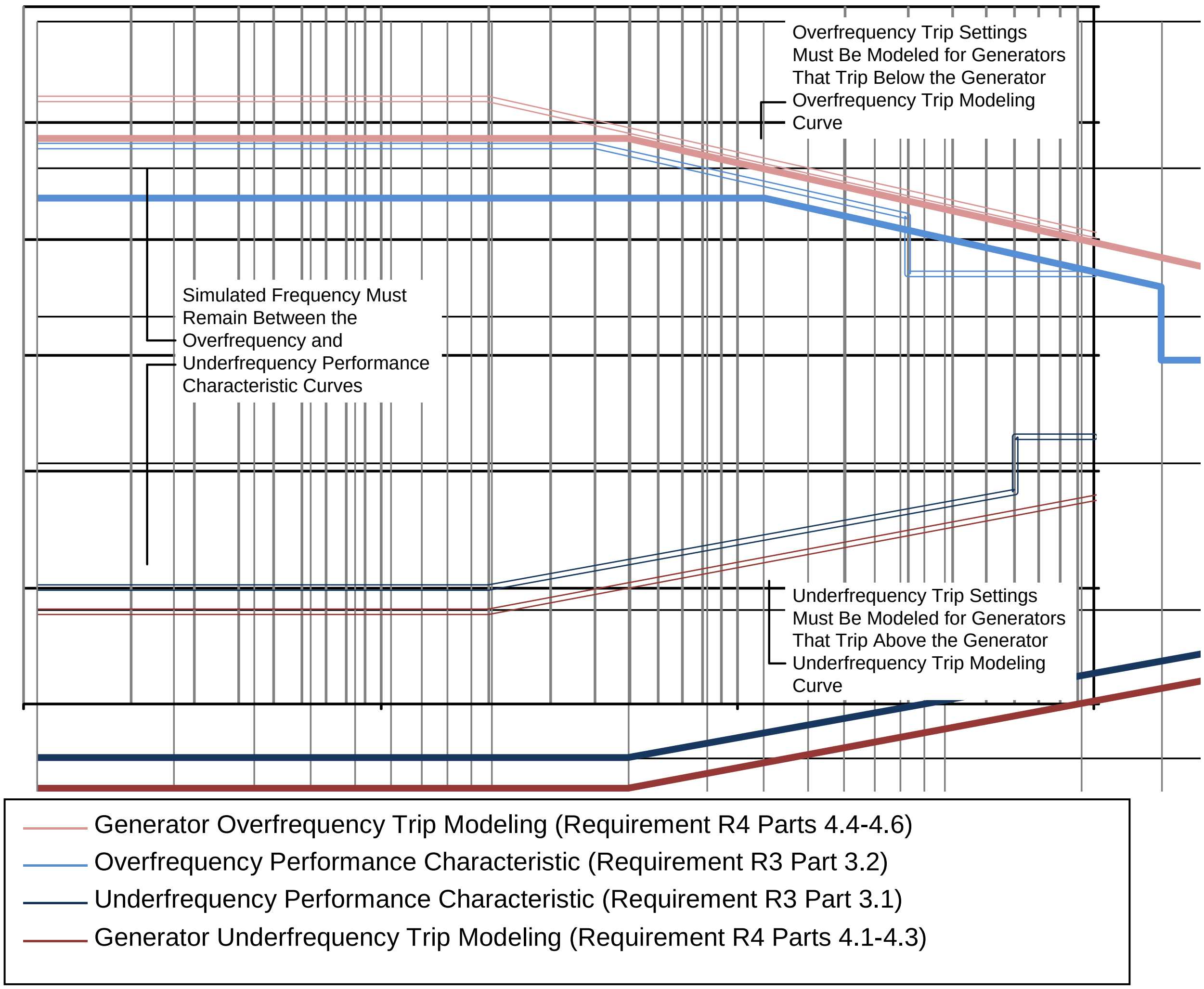
Associated Documents

Version History

Version	Date	Action	Change Tracking
1		Complete revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0	

PRC-006-1 – Attachment 1

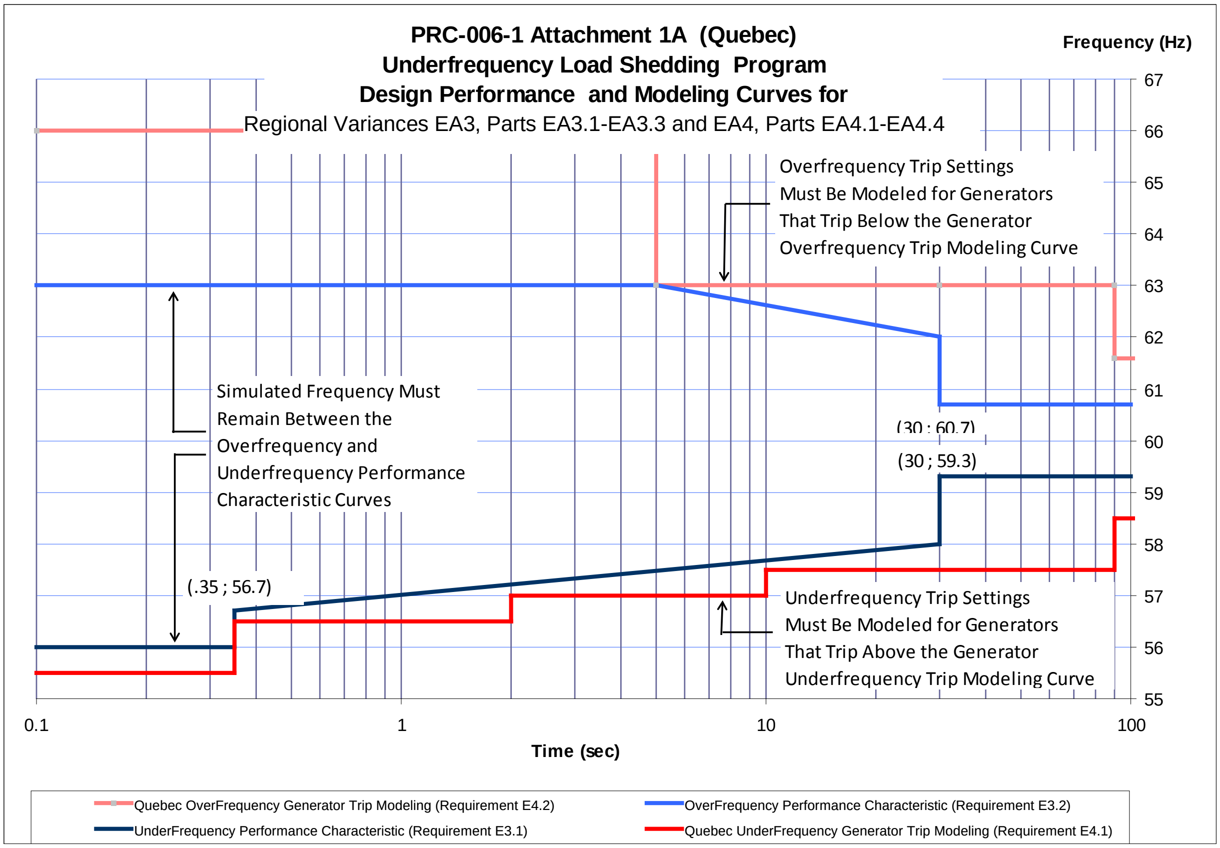
Underfrequency Load Shedding Program Design Performance and Modeling Curves for Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6



Curve Definitions

Generator Overfrequency Trip Modeling		Overfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 4 s	4 s < t ≤ 30 s	t > 30 s
f = 62.2 Hz	f = -0.686log(t) + 62.41 Hz	f = 61.8 Hz	f = -0.686log(t) + 62.21 Hz	f = 60.7 Hz

Generator Underfrequency Trip Modeling		Underfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 2 s	2 s < t ≤ 60 s	t > 60 s
f = 57.8 Hz	f = 0.575log(t) + 57.63 Hz	f = 58.0 Hz	f = 0.575log(t) + 57.83 Hz	f = 59.3 Hz


PRC-006-1 Attachment 1A (Quebec)
Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Regional Variances EA3, Parts EA3.1-EA3.3 and EA4, Parts EA4.1-EA4.4
Frequency (Hz)
67
66
65
64
63
62
61
60
59
58
57
56
55
Overfrequency Trip Settings
Must Be Modeled for Generators
That Trip Below the Generator
Overfrequency Trip Modeling Curve
Simulated Frequency Must
Remain Between the
Overfrequency and
Underfrequency Performance
Characteristic Curves
(30 ; 60.7)
(30 ; 59.3)
(.35 ; 56.7)
Underfrequency Trip Settings
Must Be Modeled for Generators
That Trip Above the Generator
Underfrequency Trip Modeling Curve
0.1
1
10
100
Time (sec)
Quebec OverFrequency Generator Trip Modeling (Requirement E4.2)
OverFrequency Performance Characteristic (Requirement E3.2)
UnderFrequency Performance Characteristic (Requirement E3.1)
Quebec UnderFrequency Generator Trip Modeling (Requirement E4.1)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Please use this form to submit comments on the first posting of the Regional Reliability Standard **PRC-006-NPCC-1—Automatic Under frequency Load Shedding**. Comments must be submitted by Feb, 24, 2011**.** You may submit the completed form using the electronic comment form posted with the standard. If you have questions please contact **Stephanie Monzon** at Stephanie.Monzon@nerc.net or by telephone at 610-608-8084.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and 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 and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

A regional reliability standard shall be: (1) a regional reliability standard that is more stringent than the continent-wide reliability standard, including a regional standard that addresses matters that the continent-wide reliability standard does not; or (2) a regional reliability standard that is necessitated by a physical difference in the bulk power system. Regional reliability standards shall provide for as much uniformity as possible with reliability standards across the interconnected bulk power system of the North American continent. Regional reliability standards, when approved by FERC and applicable authorities in Mexico and Canada shall be made part of the body of NERC reliability standards and shall be enforced upon all applicable bulk power system owners, operators, and users within the applicable area, regardless of membership in the region.

PRC-006-NPCC-1 ensures the development of an effective automatic under frequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events.

Each NPCC Regional Reliability Standard shall enable or support one or more of the NERC reliability principles, thereby ensuring that each standard serves a purpose in support of the reliability of the regional bulk power system. Each of those standards shall also be consistent with all of the NERC reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence. The NERC reliability principles supported by this standard are the following:

- **Reliability Principle 1** — Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
- **Reliability Principle 2** — The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

The proposed Northeast Power Coordinating Council (NPCC) Regional Reliability Standard is not inconsistent with, or less stringent than established NERC Reliability Standards. Once approved by the appropriate authorities, NPCC Regional Reliability Standard obligates the NPCC to monitor and enforce compliance, apply sanctions, if any, consistent with any regional agreements and the NERC rules.

PRC-006-NPCC-1 standard applies to each Transmission Owner, Distribution Provider, Generator Owner and Planning Coordinator in the NPCC region. The purpose of this standard is to ensure the development of an effective automatic under frequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events.

The NPCC **PRC-006-NPCC-1** standard contains twenty -six main requirements for applicable entities within the NPCC geographic area. The standard contains the following:

1. Requirement R1 requires that each Planning Coordinator conduct system studies to identify anticipated islands.
2. Requirement R2 requires that each Planning Coordinator provide information on anticipated islands to Transmission Owners, Distribution Providers, and Generator Owners.
3. Requirement R3 requires that each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities that sheds Load based on frequency thresholds, total nominal operating time, and amounts specified in Tables 1 through 3.
4. Requirement R4 requires that each Distribution Provider or Transmission Owner that must arm its load to trip on under frequency in order to meet its minimum obligations and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R3 shall provide their Planning Coordinator with the information in parts 4.1 through 4.4.
5. Requirement R5 requires that each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC with peak net Load connected to its Facilities shall ensure that the total nominal operating time includes the under frequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time as specified in parts 5.1 through 5.2.
6. Requirement R6 requires that each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Table 4.
7. Requirement R7 requires that each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC with peak net load connected to its

Facilities shall insure that the total nominal operating time includes the under frequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time.

8. Requirement R8 requires that each Distribution Provider and Transmission Owner set their under frequency relays with a minimum time delay as specified in parts 8.1 and 8.2.
9. Requirement R9 requires that each Planning Coordinator shall develop, implement and maintain a program to establish the appropriate inhibit thresholds to be utilized within its region's UFLS program.
10. Requirement R10 requires that each Planning Coordinator shall provide to Transmission Owners and Distribution Providers within its program area the specific inhibit thresholds applicable to each Transmission Owner or Distribution Providers.
11. Requirement R11 requires that each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R10.
12. Requirement R12 requires that each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator in accordance with R10.
13. Requirement R13 requires that each Transmission Owner and Distribution Provider shall annually provide documentation to its Planning Coordinator of the actual net load that would be shed by the UFLS relays that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year.
14. Requirement R14 requires that each Generator Owner shall ensure that their generating units do not trip for under frequency conditions above the appropriate generator under frequency trip protection settings threshold curve in Figure 1.
15. Requirement R15 requires that each Generator Owner shall transmit the generator under frequency trip setting and time constant to its Planning Coordinator within 45 days of the Planning Coordinator’s request.
16. Requirement R16 requires that each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard or an existing generator increasing its net capability by greater than 10% shall design in its in generating unit in accordance with parts 16.1 through 16.3.
17. Requirement R17 requires that each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have under frequency protections set to trip above the curve in Figure 1 shall set its protection, transmit the setting and obtain compensatory load as specified in parts 17.1 through 17.3.
18. Requirement R18 requires that each Planning Coordinator in Ontario, Quebec and the Maritime provinces apply the methodology described in Attachment A to determine the compensatory load shedding that is required in Requirement R17.3.
19. Requirement R19 requires that each Generator Owner, Distribution Provider or Transmission Owner in ISO-NE and the New York ISO apply the methodology described in Attachment B to determine the compensatory load shedding that is required in Requirement R17.3.
20. Requirement R20 requires that each Generator Owner of existing boiling water reactor nuclear generating plants with units that have under frequency relay threshold settings above the Eastern Interconnection generator tripping curve in

Figure 1 shall set their under frequency trip settings, and tolerance settings and transmit the settings as specified in parts 20.1 through 20.3.

21. Requirement R21 requires that each Transmission Owner and Distribution Provider shall annually provide its UFLS program data to its Planning Coordinator in accordance with R22 for inclusion in the Planning Coordinator's data base.

22. Requirement R22 requires that each Planning Coordinator develop, update and maintain its UFLS program data base as specified in parts 22.1 through 22.5.

23. Requirement R23 requires that each Planning Coordinator shall assess that the UFLS program requirements within its Planning Coordinator area are satisfied as implemented by Transmission Owners, Distribution Providers, and Generator Owners

24. Requirement R24 requires that each Planning Coordinator notify its Distribution Providers, Transmission Owners, and Generator Owners of changes to load distribution needed to satisfy UFLS program requirements

25. Requirement R25 requires that each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R24

26. Requirement R26 requires that each Distribution Provider, Transmission Owner and Generator Owner develop and submit an implementation plan within 90 days of the request from the Planning Coordinator in accordance with Requirement R25.

The approval process for a regional reliability standard requires NERC to publicly notice and request comment on the proposed standard. Comments shall be permitted only on the following criteria (technical aspects of the standard are vetted through the regional standards development process):

Unfair or Closed Process — The regional reliability standard was not developed in a fair and open process that provided an opportunity for all interested parties to participate. Although a NERC-approved regional reliability standards development procedure shall be presumed to be fair and open, objections could be raised regarding the implementation of the procedure.

Adverse Reliability or Commercial Impact on Other Interconnections — The regional reliability standard would have a significant adverse impact on reliability or commerce in other interconnections.

Deficient Standard — The regional reliability standard fails to provide a level of reliability of the bulk power system such that the regional reliability standard would be likely to cause a serious and substantial threat to public health, safety, welfare, or national security.

Adverse Impact on Competitive Markets within the Interconnection — The regional reliability standard would create a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability.

You are not required 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. **Was the proposed standard developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?**

   ☐ Yes
   ☐ No

   Comments:

2. **Does the proposed standard pose an adverse impact to reliability or commerce in a neighboring region or interconnection?**

   ☐ Yes
   ☐ No

   Comments:

3. **Does the proposed standard pose a serious and substantial threat to public health, safety, welfare, or national security?**

   ☐ Yes
   ☐ No

   Comments:

4. **Does the proposed standard pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?**

   ☐ Yes
   ☐ No

   Comments:

5. **Does the proposed regional reliability standard meet at least one of the following criteria?**

   - **The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard**
   - **The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard**
   - **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

   ☐ Yes
   ☐ No

   Comments:

Consideration of Comments

NPCC Automatic Underfrequency Load Shedding Program

The NPCC Automatic Underfrequency Load Shedding Drafting Team thanks all commenters who submitted comments on the proposed revisions (clean and redline) to the PRC-006-NPCC-01 standard. These standards were posted for a 30-day public comment period from November 22, 2011 through December 22, 2011. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were six sets of comments, including comments from more than 12 different people from approximately nine companies representing five of the 10 Industry Segments as shown in the table on the following pages.

All submitted comments may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/regional_standards/regional_reliability_standards_under_development.html

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 and training, Herb Schrayshuen, at 404-446-2560 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	Mike Garton	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michael Gildea	Dominion Resources Services, Inc.	MRO	5
2.	Louis Slade	Dominion Resources Services, Inc.	SERC	5
3.	Connie Lowe	Dominion Resources Services, Inc.	RFC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Annie Lauterbach	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Gregory Vasallo	Customer Service Engineering	WECC	1
2.	Laura Oliver	Customer Service Engineering	WECC	1
3.	Fred Ojima	Transmission Planning	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Individual	Michael Falvo	Independent Electricity System Operator		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
4.	Individual	Silvia Parada Mitchell	NextEra Energy	X		X		X	X				
5.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
6.	Individual	John Seelke	PSEG Services Corporation	X		X		X	X				

1. Was the proposed standard developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?

Summary Consideration:

Organization	Yes or No	Question 1 Comment
Bonneville Power Administration		BPA thanks you for the opportunity to comment on PRC-006-NPCC-01, Automatic Underfrequency Load Shedding. BPA has no comments or concerns at this time as this standard is not applicable to BPA. BPA thanks you for the opportunity to comment on PRC-006-NPCC-1. BPA has no comments or concerns at this time as this standard is not applicable to BPA. Thank you for your comment.
Response:		
Independent Electricity System Operator	Yes	
Dominion	Yes	
Northeast Utilities	Yes	
PSEG Services Corporation	No	See answer to Q4 below. Thank you for your comment. See response to Q4 below.

Organization	Yes or No	Question 1 Comment
Next Era Energy		

2. Does the proposed standard pose an adverse impact to reliability or commerce in a neighboring region or interconnection?

Summary Consideration:

Organization	Yes or No	Question 2 Comment
Dominion	Yes	R16.3 and R18 cannot be implemented. As we have stated in previous comments, we do not agree with the obligation for a non-conforming generator to procure a service (i.e., load shed) for which we have found no willing provider. It is Dominion's position that this portion of the regional standard is not feasible, given no entity will provide the service a Generator Owner is obligated to procure, which essentially guarantees that a Generator Owner of a non-conforming generator will not be able to comply with these requirements. Thank you for your comment. The Regional Standard Drafting Team acknowledges the technical challenges of administering the compensatory load shedding program and as a result has developed requirements stating that all new units shall conform to the generator tripping curve. Additionally, to address your concern regarding generators that are already interconnected and in commercial operation, non conforming generators either have existing contracts to provide compensatory load shedding or have mitigated the conditions that would trip the unit above the appropriate generator curve. These requirements are contained as criteria within the approved Directory #12 and are currently in effect throughout the NPCC region.

Organization	Yes or No	Question 2 Comment
		Further, as Dominion noted in previous comments, there are technical difficulties associated with R16.3 and R18 which would likely have an adverse impact on reliability. Specifically, shedding additional load equivalent to a non-coordinating generator would be extremely difficult to design and coordinate. The design would have to account for the real-time status and output of the generator. Otherwise, this requirement could create more problems than it attempts to solve. For example, consider a load shed program that is designed assuming the need to shed load equivalent to rated capacity for a non-coordinating generator and a frequency event occurs when this generator is off line. The program sees the frequency at the trigger level and sheds the load equivalent to the non-coordinating generator. However, since that generator wasn't actually on line, there is no additional loss of generation, but the MW load equivalent of the generator (that is not designed into the UFLS scheme) is lost anyway. If the UFLS program then implements the next level of designed reduction of load, this may result in a subsequent rebound in frequency. This may very well result in overshoot that is more than designed for, resulting in generator trip from over-frequency. Obviously, the more non-coordinating generators there are, the more difficult the task of coordination with UFLS schemes becomes and the more widespread the effects on customers. The Regional Standard Drafting Team acknowledges the technical challenges of administering the compensatory load shedding program and as a result has

Organization	Yes or No	Question 2 Comment
		developed requirements stating that all new units shall conform to the generator tripping curve. With respect to the possibility of over shedding of load due to existing compensatory load shedding not matching generation on line, the concern is acknowledged. However, an average MW output was intended to align the amount of compensatory load shedding provided with the unit output most likely to be lost if the unit tripped. It is impossible to ensure a close match between compensatory load shedding and unit output without real-time arming of UFLS. Adding precision to the amount of compensatory load shedding that is required will not improve the viability of the program. NERC Standard PRC-006-1, Automatic Underfrequency Load Shedding, has been filed with FERC and a Notice of Potential Rulemaking has been issued for industry comment (RM11-18). Additionally, under NERC Project 2007-09 Generator Verification, draft Standard PRC-024-1, Generator Frequency and Voltage Protective Relay Setting, has the potential to impact the NPCC Regional Standard as it works through the NERC and FERC approval process. Given the uncertainty of outcome, there is a potential impact associated with implementation of the Regional Standard absent FERC approved National Standards. According to the NERC Rules of Procedure, Section 302 establishes “essential attributes for technically excellent reliability standards.” Item #9 addresses practicality and states the following:”Each reliability standard shall establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.”Dominion believes the issues previously noted result in a regional standard that cannot be “practically implemented by the assigned responsibility entities.”The NPCC Regional Standards Development Procedure in Section II establishes that “in order to receive the approval of the ERO, the NPCC Reliability

Organization	Yes or No	Question 2 Comment
		Standards Development Process must also achieve the following objectives.” Specifically:” o No Adverse Impact on Reliability of the Interconnection -An NPCC Regional Reliability Standard provides a level of bulk power system reliability that is necessary and adequate to protect public health, safety, welfare, and North American security and will not have an adverse impact on the reliability of the Interconnection or other Regions within the Interconnection.”Dominion believes that the technical difficulties associated with implementing compensating load shedding, if such a service were available, for non-conforming generators may “have an adverse impact on the reliability of the Interconnection or other Regions within the Interconnection.”Therefore, Dominion believes the aforementioned issues must be resolved prior to approval of this Regional Reliability Standard by NERC and FERC. The Regional Standard Drafting Team acknowledges the technical challenges of administering the compensatory load shedding program and as a result has developed requirements stating that all new units shall conform to the generator tripping curve. Additionally, to address your concern regarding generators that are already interconnected and in commercial operation, non conforming generators either have existing contracts to provide compensatory load shedding or have mitigated the conditions that would trip the unit above the appropriate generator curve. PRC -006-NPCC -1 was developed in response to a request from the ERO to satisfy FERC Order 693. At that time, 24 standards were identified as ‘fill in the blank’ and as a result the ERO was ordered to modify the individual standards reliance on the Regional Reliability Organization. Additionally, of those 24 standards 4 were identified by the ERO and the regions to be regionally specific enough to warrant the development of a regional standard and UFLS is one of those 4 standards.

Organization	Yes or No	Question 2 Comment
		The Drafting Team made a continual effort to coordinate the standards development with other related standards that were being drafted concurrently.
Response:		
Next Era Energy	Yes	No. R16 requires generators that cannot meet the UFLS curve to have compensatory load shedding provided by a Distribution Provider (DP). This requirement is fatal flawed, because this regional reliability standard has inappropriately moved from the regional reliability organization (RRO) implementing the standard to planning coordinators, distribution providers, generator owners and transmission owners. The need for load shedding is not a bottom up analysis. Instead, the need for load shedding is more appropriately decided collectively by Transmission Planners, Transmission Operators, Reliability Coordinators and Planning Coordinators. Thus, the requirement effectively decentralizes the UFLS response, which will only serve to make the system less reliable. Thank you for your comment. The Regional Standard Drafting Team acknowledges the technical challenges of administering the compensatory load shedding program and as a result has developed requirements stating that all new units shall conform to the generator tripping curve. Additionally, PRC -006-NPCC -1 was developed in response to a request from the ERO to satisfy FERC Order 693. At that time, 24 standards were identified as 'fill in the blank' and as a result the ERO was ordered to modify the individual standards reliance on the Regional Reliability Organization.
Response:		
PSEG Services Corporation	Yes	First, the standard lacks the requirement for coordination between Planning Coordinators (PCs) who have a part of one PC's island within another PC's region (R5

Organization	Yes or No	Question 2 Comment
		in NERC PRC-006-1). UFLS program design may require coordination across regional boundaries as addressed in the NERC standard. R1 in the NPCC standard is NPCC-centric, whereas the power system is not: "Each Planning Coordinator shall establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding based on islanding criteria (required by the NERC PRC Standard on UFLS)." Thank you for your comment. The Drafting Team made a continual effort to coordinate the standards development with other related standards that were being drafted concurrently. Accordingly, Requirement R1 in NERC Standard PRC -006-1 requires a PC to consider interconnected portions of the BES in adjacent PC areas and Regional Entity areas that may form islands. Therefore the requirement to coordinate with adjacent Regional Entities was not drafted into the NPCC Regional Standard since it is already contained in PRC -006-01. In addition, R1 is both mistaken and misleading in its reference to the NERC PRC Standard on UFLS: first, the NERC standard does not address compensatory load shedding. The purpose of requirement R1 in the Regional Standard PRC -006-NPCC -1 is to provide the more specific requirements for utilizing the islands that have been identified in the NERC Standard. Accordingly, Generator Owners that trip above the curve in Figure 1 must arrange for compensatory load shedding as identified by the PC to ensure that adequate

Organization	Yes or No	Question 2 Comment
		compensatory load shedding is provided in all islands identified in Requirement R1 in which the unit may operate. Second, the NERC standard R1 requires PCs "to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands." While both the NPCC and the NERC standards require PCs to develop UFLS criteria, the NERC standard is more expansive in its inclusion of "adjacent Planning Coordinator areas and Regional Entity areas." Of course, a regional standard cannot require coordination with a PC in another region. The NERC standard is superior in that regard, and therefore the NPCC standard, which lacks this requirement, would be a detriment to reliability. With regard to coordination between the NERC standard and the NPCC Regional Standard, in this case the NERC Standard establishes the broad requirement to identify islands. The NPCC Regional Standard establishes the requirements for entities who must utilize these islands in order to develop a UFLS program. Second, UFLS programs need to be developed on an Interconnection-wide basis, not a regional basis. Frequency is an interconnection-specific parameter. This is recognized in the draft NERC standard BAL-003-1 - Frequency Response and Frequency Bias Setting, where all Balancing Authorities within an Interconnection must have a portion of the required Interconnection frequency response.

Organization	Yes or No	Question 2 Comment
		PRC -006-NPCC -1 was developed in response to a request from the ERO to satisfy FERC Order 693. At that time, 24 standards were identified as ‘fill in the blank’ and as a result the ERO was ordered to modify the individual standards reliance on the Regional Reliability Organization. Additionally, of those 24 standards 4 were identified by the ERO and the regions to be regionally specific enough to warrant the development of a regional standard and UFLS is one of those 4 standards.
Response:		
Independent Electricity System Operator	No	
Northeast Utilities	No	

3. Does the proposed standard pose a serious and substantial threat to public health, safety, welfare, or national security?

Summary Consideration:

Organization	Yes or No	Question 3 Comment
Dominion	No	None that can be determined by Dominion. Thank you for your comment.
Response:		
Independent Electricity System Operator	No	
Northeast Utilities	No	
PSEG Services Corporation	No	
Bonneville Power Administration		
NextEra Energy		

4. Does the proposed standard pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?

Summary Consideration:

Organization	Yes or No	Question 4 Comment
Dominion	Yes	See response provided to Question #2. Thank you for the comment.
Response:		
PSEG Services Corporation	Yes	NERC's PRC-006-1 does not contain a specific generator performance requirement. Generators that cannot meet the underfrequency operational assumption in Attachment 1 of the standard are modeled "as is" by the Planning Coordinator in accordance with R4, and the UFLS calculated with their actual underfrequency generator performance parameters must be provided by UFLS entities (Transmission Owners and Distribution Providers). However, NPCC's draft standard proposes specific generator performance requirements on existing in NYISO and ISO-NE -see Attachment B referenced in R18. In addition, it would require existing Generator Owner's to obtain compensatory UFLS for the early tripping of their generator's which cannot meet their specific performance requirements - see R16.3. This compensatory UFLS would be provided by Transmission Owners or Distribution Providers, but the Generator Owner would be required to obtain it. Although not directly stated in this regional standard, the presumption is that Generator Owners would be required to compensate their providers for their compensatory UFLSPSEG objects to this aspect (compensatory UFLS) of the draft regional standard for several

Organization	Yes or No	Question 4 Comment
		reasons. First, the added cost to existing Generation Owners whose generators do not meet the draft standard's performance requirements will impact the competitiveness of these generators since they must bear an added cost of acquiring compensatory UFLS that other generators will not. This violates the NPCC Regional Standards Development Procedure, which adheres to NERC's market principles - see p. 9 of the procedure. The NERC market principles state, in part, that "A reliability standard shall not give any market participant an unfair competitive advantage." Thank you for the comment. In accordance with NERC requirements and NPCC criteria an assessment of the NPCC UFLS program attributes is required to be performed by NPCC technical committees. Careful coordination of UFLS parameters is necessary to meet the performance requirements of the program and generator performance during frequency excursion is essential to maintaining the programs adequacy. Second, the requirement that existing Generator Owners acquire compensatory UFLS to make up for their generators underfrequency performance is completely absent in the Reliability Functional model description of a Generator Owner's functions. By contrast, a Distribution Provider is assigned the task of "providing] and implement[ing] load-shed capability," a result that makes sense since Distribution Providers. The Regional Standard Drafting Team acknowledges the technical challenges of administering the compensatory load shedding program and as a result has developed requirements stating that all new units shall conform to the generator tripping curve. Non conforming generators that are already interconnected and in commercial operation, either have existing contracts to provide compensatory load shedding or have mitigated the conditions that would trip the unit above the appropriate

Organization	Yes or No	Question 4 Comment
		generator curve. With regard to the concern regarding the functional model responsibilities, existing arrangements to provide compensatory load shedding are acceptable to meet the standards requirements and no new generation shall be permitted to arrange such agreements in lieu of adhering to the UFLS program parameters.
Response:		
Northeast Utilities	No	
Independent Electricity System Operator	No	
Bonneville Power Administration		
NextEra Energy		

5. Does the proposed regional reliability standard meet at least one of the following criteria?

- The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard
- The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard
- The proposed regional difference is necessitated by a physical difference in the bulk power system.

Summary Consideration:

Organization	Yes or No	Question 4 Comment
Dominion	Yes	NERC Standard PRC-006-1, Automatic Underfrequency Load Shedding, has been filed with FERC and a Notice of Potential Rulemaking has been issued for industry comment (RM11-18). Additionally, under NERC Project 2007-09 Generator Verification, draft Standard PRC-024-1, Generator Frequency and Voltage Protective Relay Setting, has the potential to impact the NPCC Regional Standard as it works through the NERC and FERC approval process. Given the uncertainty of outcome, there is a potential impact associated with implementation of the Regional Standard absent FERC approved National Standards. Thank you for the comment. PRC -006-NPCC -1 was developed in response to a request from the ERO to satisfy FERC Order 693. At that time, 24 standards were identified as 'fill in the blank' and as a result the ERO was ordered to modify the individual standards reliance on the Regional Reliability Organization. The Drafting Team made a continual effort to coordinate the standards development with other related standards that were being drafted concurrently.
Response:		

Organization	Yes or No	Question 4 Comment
PSEG Services Corporation	Yes	While there are more specific criteria and more requirements, the standard has the deficiencies cited in Q2 and Q4 above. Thank you for the comment. Please see responses to Q2 and Q4 above. ADDITIONAL COMMENTS not addressed in any prior questions: The standard may violate the market principle that states "Standards shall not define an adequate amount of, or require expansion of, bulk power system resources or delivery capability." Delivery capability of a generator includes the frequency range over which it can safely and reliably produce MVA output. As written the standard defines adequacy of delivery capability and also would require Generator Owners of units that cannot meet that adequacy requirement to either increase their generators' underfrequency response capability or acquire compensatory UFLS, presumably at their cost. This violates the market principle. Thank you for the comment. In accordance with NERC requirements and NPCC criteria an assessment of the NPCC UFLS program attributes is required to be performed by NPCC technical committees. Careful coordination of UFLS parameters is necessary to meet the performance requirements of the program and generator performance during frequency excursion is essential to maintaining the programs adequacy.
Response:		
Independent Electricity	Yes	

Organization	Yes or No	Question 4 Comment
System Operator		
Northeast Utilities	Yes	
Bonneville Power Administration		
NextEra Energy		

END OF REPORT

Individual or group. (6 Responses)
Name (3 Responses)
Organization (3 Responses)
Group Name (3 Responses)
Lead Contact (3 Responses)
Question 1 (4 Responses)
Question 1 Comments (6 Responses)
Question 2 (5 Responses)
Question 2 Comments (6 Responses)
Question 3 (4 Responses)
Question 3 Comments (6 Responses)
Question 4 (4 Responses)
Question 4 Comments (6 Responses)
Question 5 (4 Responses)
Question 5 Comments (6 Responses)

Individual
Michael Falvo
Independent Electricity System Operator
Yes
No
No
No
Yes
Group
Compliance & Responsibility
Silvia Parada Mitchell
Yes
No. R16 requires generators that cannot meet the UFLS curve to have compensatory load shedding provided by a Distribution Provider (DP). This requirement is fatal flawed, because this regional reliability standard has inappropriately moved from the regional reliability organization (RRO) implementing the standard to planning coordinators, distribution providers, generator owners and transmission owners. The need for load shedding is not a bottom up analysis. Instead, the need for load shedding is more appropriately decided collectively by Transmission Planners, Transmission Operators, Reliability Coordinators and Planning Coordinators. Thus, the requirement effectively decentralizes the UFLS response, which will only serve to make the system less reliable.
Individual
Michael Lombardi
Northeast Utilities
Yes
No
No

No
Yes
Group
Dominion
Mike Garton
Yes
Yes
R16.3 and R18 cannot be implemented. As we have stated in previous comments, we do not agree with the obligation for a non-conforming generator to procure a service (i.e., load shed) for which we have found no willing provider. It is Dominion's position that this portion of the regional standard is not feasible, given no entity will provide the service a Generator Owner is obligated to procure, which essentially guarantees that a Generator Owner of a non-conforming generator will not be able to comply with these requirements. Further, as Dominion noted in previous comments, there are technical difficulties associated with R16.3 and R18 which would likely have an adverse impact on reliability. Specifically, shedding additional load equivalent to a non-coordinating generator would be extremely difficult to design and coordinate. The design would have to account for the real-time status and output of the generator. Otherwise, this requirement could create more problems than it attempts to solve. For example, consider a load shed program that is designed assuming the need to shed load equivalent to rated capacity for a non-coordinating generator and a frequency event occurs when this generator is off line. The program sees the frequency at the trigger level and sheds the load equivalent to the non-coordinating generator. However, since that generator wasn't actually on line, there is no additional loss of generation, but the MW load equivalent of the generator (that is not designed into the UFLS scheme) is lost anyway. If the UFLS program then implements the next level of designed reduction of load, this may result in a subsequent rebound in frequency. This may very well result in overshoot that is more than designed for, resulting in generator trip from over-frequency. Obviously, the more non-coordinating generators there are, the more difficult the task of coordination with UFLS schemes becomes and the more widespread the effects on customers. NERC Standard PRC-006-1, Automatic Underfrequency Load Shedding, has been filed with FERC and a Notice of Potential Rulemaking has been issued for industry comment (RM11-18). Additionally, under NERC Project 2007-09 Generator Verification, draft Standard PRC-024-1, Generator Frequency and Voltage Protective Relay Setting, has the potential to impact the NPCC Regional Standard as it works through the NERC and FERC approval process. Given the uncertainty of outcome, there is a potential impact associated with implementation of the Regional Standard absent FERC approved National Standards. According to the NERC Rules of Procedure, Section 302 establishes "essential attributes for technically excellent reliability standards." Item #9 addresses practicality and states the following: "Each reliability standard shall establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter." Dominion believes the issues previously noted result in a regional standard that cannot be "practically implemented by the assigned responsibility entities." The NPCC Regional Standards Development Procedure in Section II establishes that "in order to receive the approval of the ERO, the NPCC Reliability Standards Development Process must also achieve the following objectives." Specifically: "• No Adverse Impact on Reliability of the Interconnection —An NPCC Regional Reliability Standard provides a level of bulk power system reliability that is necessary and adequate to protect public health, safety, welfare, and North American security and will not have an adverse impact on the reliability of the Interconnection or other Regions within the Interconnection." Dominion believes that the technical difficulties associated with implementing compensating load shedding, if such a service were available, for non-conforming generators may "have an adverse impact on the reliability of the Interconnection or other Regions within the Interconnection." Therefore, Dominion believes the aforementioned issues must be resolved prior to approval of this Regional Reliability Standard by NERC and FERC.
No
None that can be determined by Dominion.
Yes
See response provided to Question #2.
Yes
NERC Standard PRC-006-1, Automatic Underfrequency Load Shedding, has been filed with FERC and a Notice of Potential Rulemaking has been issued for industry comment (RM11-18). Additionally, under NERC Project 2007-09 Generator Verification, draft Standard PRC-024-1, Generator Frequency and Voltage Protective Relay Setting, has the potential to impact the NPCC Regional Standard as it works through the NERC and FERC approval process. Given the uncertainty of outcome, there is a potential impact associated with implementation of the Regional Standard absent FERC approved National Standards.
Individual
John Seelke
PSEG Services Corporation

No
See answer to Q4 below.
Yes
First, the standard lacks the requirement for coordination between Planning Coordinators (PCs) who have a part of one PC's island within another PC's region (R5 in NERC PRC-006-1). UFLS program design may require coordination across regional boundaries as addressed in the NERC standard. R1 in the NPCC standard is NPCC-centric, whereas the power system is not: "Each Planning Coordinator shall establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding based on islanding criteria (required by the NERC PRC Standard on UFLS)." In addition, R1 is both mistaken and misleading in its reference to the NERC PRC Standard on UFLS: first, the NERC standard does not address compensatory load shedding. Second, the NERC standard R1 requires PCs "to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands." While both the NPCC and the NERC standards require PCs to develop UFLS criteria, the NERC standard is more expansive in its inclusion of "adjacent Planning Coordinator areas and Regional Entity areas." Of course, a regional standard cannot require coordination with a PC in another region. The NERC standard is superior in that regard, and therefore the NPCC standard, which lacks this requirement, would be a detriment to reliability. Second, UFLS programs need to be developed on an Interconnection-wide basis, not a regional basis. Frequency is an interconnection-specific parameter. This is recognized in the draft NERC standard BAL-003-1 – Frequency Response and Frequency Bias Setting, where all Balancing Authorities within an Interconnection must have a portion of the required Interconnection frequency response.
No
Yes
NERC's PRC-006-1 does not contain a specific generator performance requirement. Generators that cannot meet the underfrequency operational assumption in Attachment 1 of the standard are modeled "as is" by the Planning Coordinator in accordance with R4, and the UFLS calculated with their actual underfrequency generator performance parameters must be provided by UFLS entities (Transmission Owners and Distribution Providers). However, NPCC's draft standard proposes specific generator performance requirements on existing in NYISO and ISO-NE –see Attachment B referenced in R18. In addition, it would require existing Generator Owner's to obtain compensatory UFLS for the early tripping of their generator's which cannot meet their specific performance requirements – see R16.3. This compensatory UFLS would be provided by Transmission Owners or Distribution Providers, but the Generator Owner would be required to obtain it. Although not directly stated in this regional standard, the presumption is that Generator Owners would be required to compensate their providers for their compensatory UFLS PSEG objects to this aspect (compensatory UFLS) of the draft regional standard for several reasons. First, the added cost to existing Generation Owners whose generators do not meet the draft standard's performance requirements will impact the competitiveness of these generators since they must bear an added cost of acquiring compensatory UFLS that other generators will not. This violates the NPCC Regional Standards Development Procedure, which adheres to NERC's market principles – see p. 9 of the procedure. The NERC market principles state, in part, that "A reliability standard shall not give any market participant an unfair competitive advantage." Second, the requirement that existing Generator Owners acquire compensatory UFLS to make up for their generators underfrequency performance is completely absent in the Reliability Functional model description of a Generator Owner's functions. By contrast, a Distribution Provider is assigned the task of "provid[ing] and implement[ing] load-shed capability," a result that makes sense since Distribution Providers.
Yes
While there are more specific criteria and more requirements, the standard has the deficiencies cited in Q2 and Q4 above. ADDITIONAL COMMENTS not addressed in any prior questions: The standard may violate the market principle that states "Standards shall not define an adequate amount of, or require expansion of, bulk power system resources or delivery capability." Delivery capability of a generator includes the frequency range over which it can safely and reliably produce MVA output. As written the standard defines adequacy of delivery capability and also would require Generator Owners of units that cannot meet that adequacy requirement to either increase their generators' underfrequency response capability or acquire compensatory UFLS, presumably at their cost. This violates the market principle.
Group
Bonneville Power Administration
Annie Lauterbach
BPA thanks you for the opportunity to comment on PRC-006-NPCC-01, Automatic Underfrequency Load Shedding. BPA has no comments or concerns at this time as this standard is not applicable to BPA. BPA thanks you for the opprotunity to comment on PRC-006-NPCC-1. BPA has no comments or concerns at this time as this standard is not applicable to BPA.

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PRC-006-NPCC-1 Automatic Underfrequency Load Shedding

Implementation Plan

Background:

The purpose of this draft Regional Standard is to ensure the development and maintenance of an effective and coordinated Automatic Underfrequency Load Shedding program in order to preserve the reliability and integrity of the bulk power system during declining system frequency events.

In the developing the Implementation Plan for PRC-006-NPCC-01 the Standard Drafting Team considered the following:

1. The requirements listed in this Regional Standard are intended to cover all aspects of the UFLS program. The Regional Standard Drafting Team (RSDT) coordinated its development with the draft NERC UFLS Standard PRC-006. The intent of this Regional Standard is to be more stringent than the continent wide standard while incorporating specific program characteristics into the requirements.
2. The Implementation Plan for this standard is based, in part, on the timelines reflected in the existing and ongoing Implementation Plan for NPCC Directory #12 absent the annual milestones required by Directory #12.

Effective Dates:

Eastern Interconnection & Québec Interconnection Portions of NPCC Excluding the Independent Electricity System Operator (IESO) Planning Coordinator Area of NPCC in Ontario, Canada.

1. The effective date for requirements R1, R2, R3, R4, R5, R6, and R7 is the first day of the first calendar quarter following applicable regulatory approval but no earlier than Jan 1, 2016 to allow for the existing implementation plan to be completed.

2. The effective date for requirements R8 through R23 is the first day of the first calendar quarter two years following applicable governmental and regulatory approval.

Independent Electricity System Operator (IESO) Planning Coordinator's Area of NPCC in Ontario, Canada

1. Effective the first day of the first calendar quarter following applicable governmental and regulatory approval but no earlier than April 1, 2017.

References:

- 2006 Assessment of UFLS Adequacy Part 3 Assessment of Program Modifications.
- SS38 Underfrequency Load Shedding Support Studies

NPCC Criteria:

- Directory #12 Underfrequency Load Shedding Program Requirements.
- A-7 NPCC Glossary of Terms.

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. NPCC Regional Standards Committee (RSC) authorized posting UFLS RSAR development on August 20, 2008.
2. UFLS RSAR posted on NPCC website on August 25, 2008.
3. NPCC Reliability Coordinating Committee (RCC) approved the Task Force on System Studies (TFSS) as the lead task force to initiate drafting a UFLS Regional Standards on September 4, 2008.
4. NPCC UFLS Regional Standard Drafting Team initial meeting on January 27, 2009.
5. First draft posted on the NPCC Website July 13, 2009 for a 45 day comment period.
6. Second draft posted on the NPCC Website May 26, 2010 for a 45 day comment period.
7. Third draft posted on the NPCC Website May 6, 2011 for a 45 day comment period.

Description of Current Draft:

This is the third draft of the proposed standard.

Future Development Plan:

Anticipated Action	Anticipated Date
1. Post the initial draft of the standard for 45 day comment period.	July 13, 2009 to August 27, 2009
2. Respond to comments on the first posting and post revised standard and implementation plan for a 45 day comment period.	September 2009 to May 2010 May 26, 2010 to July 9th, 2010
3. Respond to comments on the 2nd posting.	July 2010 to October 2010
4. Obtain RSC approval to move the standard forward to balloting.	November 2010
5. Post the standard and implementation plan for a 30 day pre ballot review.	December 2010

6. Conduct a ten day ballot.	December 2010
7. Respond to ballot comments and post revised standard and implementation plan for a 45 day comment period.	May, 2011.
8. Respond to comments on the 3rd posting.	July 2011
9. Obtain RSC approval to move the standard forward to balloting.	August 2011
10. Post the standard and implementation plan for a 30 day pre ballot review.	August 2011
11. Conduct a ten day ballot.	September 2011
12. Membership Approval.	September 2011.

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 NERC 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 NPCC Glossary.

In the standards, defined terms are indicated with its first letter capitalized.

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**
2. **Number:** PRC-006-NPCC-1
3. **Purpose:** To provide a regional reliability standard that ensures the development of an effective automatic underfrequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS reliability standard characteristics.
4. **Applicability:**
   - **4.1.** Generator Owner
   - **4.2.** Planning Coordinator
   - **4.3.** Distribution Provider
   - **4.4.** Transmission Owner
5. **(Proposed) Effective Date:** To be established.

B. Requirements

R1 Each Planning Coordinator shall establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding based on islanding criteria (required by the NERC PRC Standard on UFLS). [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R2 Each Planning Coordinator shall, within 30 days of completion of its system studies required by the NERC PRC Standard on UFLS, identify to the Regional Entity the generation facilities within its Planning Coordinator Area necessary to support the UFLS program performance characteristics. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R3 Each Planning Coordinator shall provide to the Transmission Owner, Distribution Provider, and Generator Owner within 30 days upon written request the requirements for entities aggregating the UFLS programs and requirements for compensatory load shedding program derived from each Planning Coordinator's system studies as determined by Requirement R1. [Violation Risk Factor: Low] [Time Horizon: Long Term Planning]

R4 Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program reflecting normal operating conditions excluding outages for its Facilities based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3, or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1 and acting as a single entity, provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load, based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R5 Each Distribution Provider or Transmission Owner that must arm its load to trip on underfrequency in order to meet its requirements as specified and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4 above, as applicable depending on its total peak net Load shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

5.1 Inform its Planning Coordinator of the need to exceed the stated tolerances or the number of stages as shown in UFLS Attachment C, Table 1 if applicable and

5.2 Provide its Planning Coordinator with a technical study that demonstrates that the Distribution Providers or Transmission Owners specific deviations from the requirements of UFLS Attachment C, Table 1 will not have a significant adverse impact on the bulk power system.

5.3 Inform its Planning Coordinator of the need to exceed the stated tolerances of UFLS Attachment C, Table 2 or Table 3, and in the case of Attachment C, Table 2 only, the need to deviate from providing two stages of UFLS, if applicable, and

5.4 Provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Attachment C Table 2 or Attachment C Table 3.

R6 Each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R7 Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with the following minimum time delay:

7.1 Eastern Interconnection – 100 ms

7.2 Québec Interconnection – 200 ms

[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R8 Each Planning Coordinator shall develop and review once per calendar year settings for inhibit thresholds (such as but not limited to voltage, current and time) to be utilized within its region's UFLS program. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R9 Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 days of the initial determination of those inhibit thresholds and within 30 days of any changes to those thresholds. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

R10 Each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R9. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

R11 Each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R9. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R12 Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage coincident with their integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would be opened by the UFLS relays. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]

R13 Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in Requirements R16 and R19. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R14 Each Generator Owner shall transmit the generator underfrequency trip setting and time delay to its Planning Coordinator within 45 days of the Planning Coordinator's request. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

R15 Each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard, or an existing generator increasing its net capability by greater than 10% shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

15.1 Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 1.

15.2 Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1.

R16 Each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1 shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

16.1 Set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

16.2 Transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

16.3 Have compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of their generator due to early tripping.

R17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall apply the criteria described in Attachment B to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R19 Each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 1, based on their licensing design basis, shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

19.1 Set the underfrequency protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8Hz.

19.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.

19.3 Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.

R20 The Planning Coordinator shall update its UFLS program database as specified by the NERC PRC Standard on UFLS. This database shall include the following information: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

20.1 For each UFLS relay, including those used for compensatory load shedding, the amount and location of load shed at peak, the corresponding frequency threshold and time delay settings.

20.2 The buses at which the Load is modeled in the NPCC library power flow case.

20.3 A list of all generating units that may be tripped for underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, including the frequency trip threshold and time delay for each protection system.

20.4 The location and amount of additional elements to be switched for voltage control that are coordinated with UFLS program tripping.

20.5 A list of all UFLS relay inhibit functions along with the corresponding settings and locations of these relays.

R21 Each Planning Coordinator shall notify each Distribution Provider, Transmission Owner, and Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program performance characteristics as specified by the NERC PRC Standard on UFLS.[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R22 Each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R23 Each Distribution Provider, Transmission Owner and Generator Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

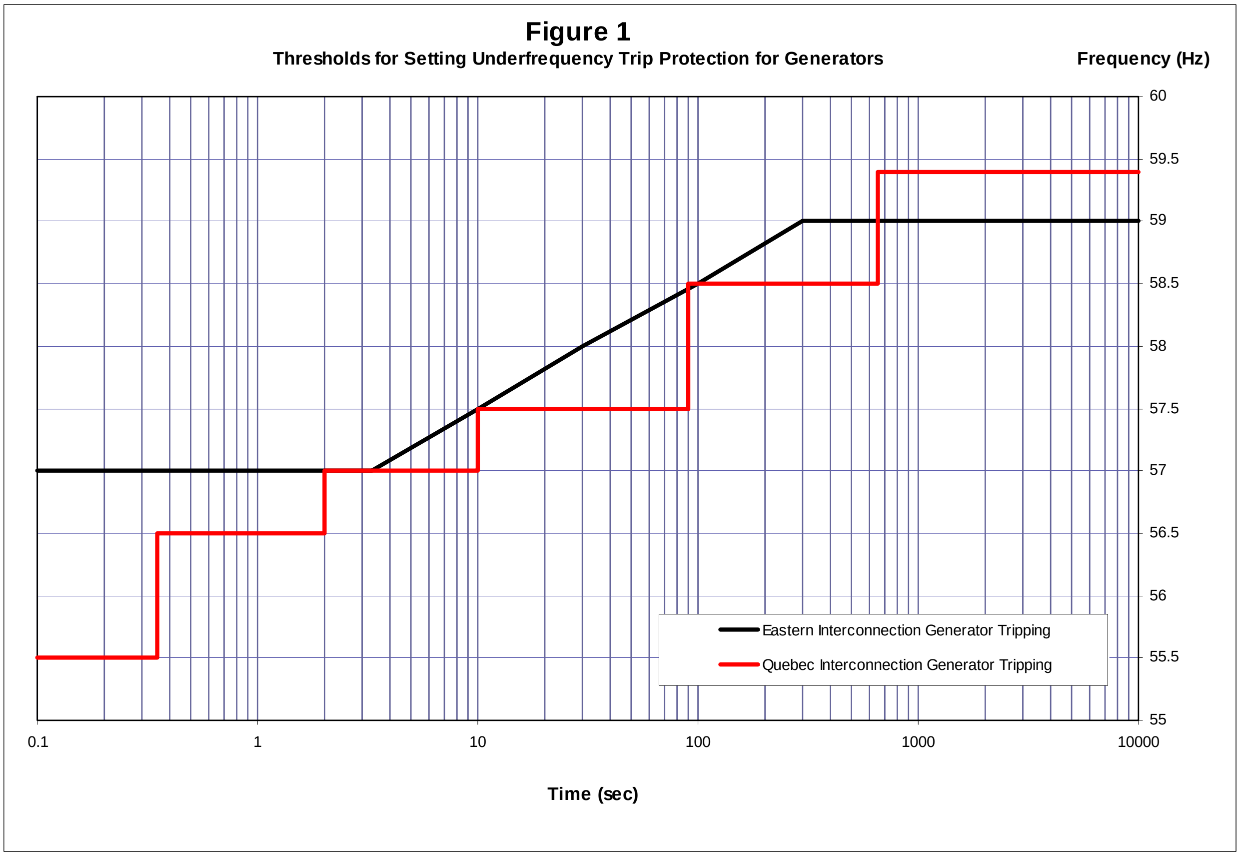

Figure 1
Thresholds for Setting Underfrequency Trip Protection for Generators
Frequency (Hz)
60
59.5
59
58.5
58
57.5
57
56.5
56
55.5
55
0.1
1
10
100
1000
10000
Time (sec)
Eastern Interconnection Generator Tripping
Quebec Interconnection Generator Tripping

C. Measures

M1 Each Planning Coordinator shall have evidence such as reports, system studies and/or real time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

M2. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

M3 Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3.

M4 Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped, and the corresponding frequency thresholds, on those circuits included in its UFLS program to achieve the individual and cumulative percentages identified in Requirement R4. (Attachment C Tables 1-3).

M5 Each Distribution Provider or Transmission Owner shall have evidence such as reports, analysis, system studies and dated documentation that demonstrates that it meets Requirement R5.

M6 Each Distribution Provider and Transmission Owner in the Québec Interconnection shall have evidence such as documentation or reports containing the location and amount of load to be tripped and the corresponding frequency thresholds on those circuits included in its UFLS program to achieve the load values identified in Table 4 of Requirement R6. (Attachment C Table 4).

M7 Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R7.

M8 Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R8.

M9 Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R9.

M10 Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets or other documentation that demonstrates that it meets Requirement R10.

M11 Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R11.

M12 Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the frequency set point, the net amount of load shed and the percentage of its peak load at each stage of its UFLS program coincident with the integrated hourly peak of the previous year that demonstrates that it meets Requirement R12.

M13 Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R13.

M14 Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R14.

M15 Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R15.

M16 Each Generator Owner with existing non-nuclear units in service prior to the effective date of this Standard which have underfrequency tripping that is not compliant with Requirement R13 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R16.

M17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall provide evidence such as emails, memorandum or other documentation that demonstrates that it followed the methodology described in Attachment A and meets Requirement R17.

M18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall provide evidence such as emails, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R18.

M19 Each Generator Owner of nuclear units that have been specifically identified by NPCC as having generator trip settings above the generator trip curve in Figure 1 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R19.

M20 Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the requirements of Requirement R20.

M21 Each Planning Coordinator shall provide evidence such as emails, memorandum or other dated documentation that it meets Requirement R21.

M22 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as reports, spreadsheets or other documentation that demonstrates that it meets Requirement R22.

M23 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates it meets Requirement 23.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

NPCC Compliance Committee

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable

1.3. Data Retention

The Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 4, 5, 6,7,10, 11, and 12.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 3, 8, 9, 20, and 21.

The Planning Coordinator in Ontario, Quebec, and the Maritime Provinces shall keep evidence for three calendar years for Measure 17.

The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measures 18, 22, and 23.

The Generator Owner shall keep evidence for three calendar years for Measures 13, 14, 15, 16, and 19.

1.4. Compliance Monitoring and Assessment Processes

Self -Certifications.

Spot Checking.

Compliance Audits.

Self- Reporting.

Compliance Violation Investigations.

Complaints.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	**N/A**	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs. or Did not establish requirements for compensatory load shedding.	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs and did not establish requirements for compensatory load shedding.
R2	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 30 days but less than 41 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 40 days but less than 51 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 50 days but less than 61 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 60 days after completion of the system studies. or The Planning Coordinator did not identify the generation facilities within its Planning Coordinator Area necessary to support the UFLS program.
R3	The Planning Coordinator provided the requested information, but did so more than 30 days but less than 41 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 40 days but less than 51 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 50 days but less than 61 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 60 days after the request. or The Planning Coordinator failed to provide the requested information.

R4	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to implement an automatic UFLS program reflecting normal operating conditions excluding outages, for its Facilities or collectively implemented by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on frequency thresholds, total nominal operating time, and amounts specified in the appropriate included tables.
R5	N/A	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not inform the Planning Coordinator of the need to exceed the stated tolerances of UFLS Table 2 or Table 3, and in the case of Table	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not provide the Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or	The Distribution Provider or Transmission Owner did not arm its load to trip on underfrequency in order to meet its minimum obligations and in doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load.

		2 only, the need to deviate from providing two stages of UFLS.	Transmission Owner to comply with the appropriate table.	
R6	N/A	N/A	T	The Distribution Provider or Transmission Owner in the Québec Interconnection portion of NPCC did not implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or did not collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4.
R7	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to set

				an underfrequency relay that is part of its region's UFLS program as specified in Requirement R7.
R8		N/A	The Planning Coordinator developed inhibit thresholds as specified in Requirement R8 but did not perform the review once per calendar year.	The Planning Coordinator did not develop inhibit thresholds as specified in Requirement R8.
R9	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 30 days but less than 41 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 40 days but less than 51 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 50 days but less than 61 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 60 days after the initial determination or any subsequent change to the inhibit thresholds. or The Planning Coordinator did not provide to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds.
R10	N/A	N/A	N/A	The Distribution Provider or Transmission Owner did not implement the inhibit threshold based on the notification provided by the Planning Coordinator in accordance with Requirement R9.

R11	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider or Transmission Owner did not develop its implementation plan.
R12				The Transmission Owner or Distribution Provider did not provide documentation to its Planning Coordinator of actual net load data or updates to the data that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year.
R13	N/A	N/A	N/A	The Generator Owner did not set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted.

R14	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 45 days and less than 56 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 55 days and less than 66 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 65 days and less than 76 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 75days after the Planning Coordinator's request. or The Generator Owner did not transmit the generator underfrequency trip setting and time delay to its Planning Coordinator.
R15	N/A	N/A	The Generator Owner did not fulfill the obligation of Requirement R15; Part 15.1 OR did not fulfill the obligation of Requirement R15, Part 15.2.	The Generator Owner did not fulfill the obligation of Requirement R15, Part 15.1 and did not fulfill the obligation of Requirement R15, Part 15.2.
R16	N/A	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.2.	The Generator Owner did not fulfill the obligation of Requirement R16; Part 16.1 OR did not fulfill the obligation of Requirement R16, Part 16.3.	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.1 and did not fulfill the obligation of Requirement R16, Part 16.3.

R17	N/A	N/A	N/A	The Planning Coordinator did not apply the methodology described in Attachment A to determine the compensatory load shedding that is required.
R18	N/A	N/A	N/A	The Generator Owner, Distribution Provider, or Transmission Owner did not apply the methodology described in Attachment B to determine the compensatory load shedding that is required.
R19	N/A	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.3.	The Generator Owner did not fulfill the obligation of Requirement R19; Part 19.1 OR did not fulfill the obligation of Requirement R19, Part 19.2.	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.1 and did not fulfill the obligation of Requirement R19, Part 19.2.
R20	The Planning Coordinator did not have data in its database for one of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for two of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for three of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for four or more of the parameters listed in Requirement 20, Parts 20.1 through 20.5.

R21	N/A	N/A	N/A	The Planning Coordinator did not notify a Distribution Provider, Transmission Owner, or Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program requirements.
R22	N/A	N/A	N/A	The Distribution Provider, Transmission Owner, or Generator Owner did not implement the load distribution changes based on the notification provided by the Planning Coordinator.
R23	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider. Transmission Owner or Generator Owner did not develop its implementation plan.

PRC-006-NPCC-1 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with underfrequency protections set to trip above the appropriate curve in Figure 1. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all islands identified in Requirement R1 in which the unit may operate.

The methodology below provides a set of criteria for the Planning Coordinator to follow for determining compensatory load shedding requirements:

1. The Planning Coordinator shall identify, compile and maintain an updated list of all existing non-nuclear generating units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1. The list shall include the following information for each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 All islands within which the unit may operate, as identified in Requirement R1

2. For each generating unit identified in (1) above, the Planning Coordinator shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator in Requirement R1 within which the generator may operate to provide compensatory load shedding.

    2.2 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4..

    2.3 The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 during an underfrequency event. If the highest

frequency at which the subject generator will trip above the appropriate curve in Figure 1 does not correspond to a specific UFLS program stage threshold setting, the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1.

2.4 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment B

Compensatory Load Shedding Criteria for ISO-NE and NYISO:

The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 1 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements:

1. The Generator Owner shall identify and compile a list of all existing non-nuclear generating units in service prior to the effective date of this standard that has underfrequency protection set to trip above the appropriate curve in Figure 1. The list shall include the following information associated with each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.

2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 1, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.2 In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 1, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.3 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.4 The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip.

2.5 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment C

UFLS Table 1: Eastern Interconnection

Distribution Providers and Transmission Owners with 100 MW or more of peak net Load shall implement a UFLS program with the following attributes:

Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
59.5	0.30	6.5 – 7.5	6.5 – 7.5
59.3	0.30	6.5 – 7.5	13.5 – 14.5
59.1	0.30	6.5 – 7.5	20.5 – 21.5
58.9	0.30	6.5 – 7.5	27.5 – 28.5
59.5	10.0	2 – 3	29.5 – 31.5

UFLS Table 2: Eastern Interconnection

Distribution Providers and Transmission Owners with 50 MW or more and less than 100 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time(s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	14-25	14-25
2	59.1	0.30	14-25	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 3: Eastern Interconnection

Distribution Providers and Transmission Owners with 25 MW or more and less than 50 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	28-50	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 4: Quebec Interconnection

	Rate	Frequency (Hz)	MW at peak (*Load must be fixed at all times when above 60% of peak load..)	Mvar at peak	Total Nominal Operating Time (s) [2]
Threshold Stage 1	——	58.5	1000*	1000	0.30
Threshold Stage 2	——	58.0	800*	800	0.30
Threshold Stage 3	——	57.5	800	800	0.30
Threshold Stage 4	——	57.0	800	800	0.30
Threshold Stage 5 (anti-stall)	——	59.0	500	500	20.0
Slope Stage 1	-0.3 Hz/s	58.5	400	400	0.30
Slope Stage 2	-0.4 Hz/s	59.8	800*	800	0.30
Slope Stage 3	-0.6 Hz/s	59.8	800*	800	0.30
Slope Stage 4	-0.9 Hz/s	59.8	800	800	0.30

2. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time. The underfrequency relay operating time shall be measured from the time when the frequency passes through the frequency threshold set point.

NERC

Unofficial Comment Form for Regional Reliability Standard
PRC-006-NPCC-1

Please **DO NOT** use this form. Please use the electronic form located at the link below to submit comments on the Regional Reliability Standard **PRC-006-NPCC-1** comments must be submitted by December 22, 2011. If you have questions please contact Howard Gugel at howard.gugel@nerc.net or Barb Nutter at barbara.nutter@nerc.net

http://www.nerc.com/filez/regional_standards/regional_reliability_standards_under_development.html

Background Information

A regional reliability standard shall be: (1) a regional reliability standard that is more stringent than the continent-wide reliability standard, including a regional standard that addresses matters that the continent-wide reliability standard does not; or (2) a regional reliability standard that is necessitated by a physical difference in the bulk power system. Regional reliability standards shall provide for as much uniformity as possible with reliability standards across the interconnected bulk power system of the North American continent. Regional reliability standards, when approved by FERC and applicable authorities in Mexico and Canada shall be made part of the body of NERC reliability standards and shall be enforced upon all applicable bulk power system owners, operators, and users within the applicable area, regardless of membership in the region.

PRC-006-NPCC-1 ensures the development of an effective Automatic Underfrequency Load Shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events.

Each **NPCC** Regional Reliability Standard shall enable or support one or more of the NERC reliability principles, thereby ensuring that each standard serves a purpose in support of the reliability of the regional bulk electric system. Each of those standards shall also be consistent with all of the NERC reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence. The NERC reliability principles supported by this standard are the following:

- **Reliability Principle 1** — Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

- **Reliability Principle 2** — The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

The proposed **NPCC** Regional Reliability Standard is not inconsistent with, or less stringent than established NERC Reliability Standards. Once approved by the appropriate authorities, the **NPCC** Regional Reliability Standard obligates the **NPCC** to monitor and enforce compliance, apply sanctions, if any, consistent with any regional agreements and the NERC rules.

PRC-006-NPCC-1 standard applies to each Generator Owner, Planning Coordinator, Distribution Provider and Transmission Owner in the NPCC region. The purpose of this standard is to provide a regional reliability standard that ensures the development of an effective automatic underfrequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS reliability standard characteristics.

The NPCC **PRC-006-NPCC-1** standard contains 23 main requirements for applicable entities within the NPCC geographic area. The standard contains the following:

R1 Each Planning Coordinator shall establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding based on islanding criteria (required by the NERC PRC Standard on UFLS).

R2 Each Planning Coordinator shall, within 30 days of completion of its system studies required by the NERC PRC Standard on UFLS, identify to the Regional Entity the generation facilities within its Planning Coordinator Area necessary to support the UFLS program performance characteristics.

R3 Each Planning Coordinator shall provide to the Transmission Owner, Distribution Provider, and Generator Owner within 30 days upon written request the requirements for entities aggregating the UFLS programs and requirements for compensatory load shedding program derived from each Planning Coordinator's system studies as determined by Requirement R1.

R4 Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program reflecting normal operating conditions excluding outages for its Facilities based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3, or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1 and acting as a single entity, provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load, based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3.

R5 Each Distribution Provider or Transmission Owner that must arm its load to trip on underfrequency in order to meet its requirements as specified and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4 above, as applicable depending on its total peak net Load shall:

R6 Each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4.

R7 Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with the following minimum time delay:
7.1 Eastern Interconnection – 100 ms
7.2 Québec Interconnection – 200 ms

R8 Each Planning Coordinator shall develop and review once per calendar year settings for inhibit thresholds (such as but not limited to voltage, current and time) to be utilized within its region's UFLS program.

R9 Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 days of the initial determination of those inhibit thresholds and within 30 days of any changes to those thresholds.

R10 Each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R9.

R11 Each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R9.

R12 Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage coincident with their integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would be opened by the UFLS relays.

R13 Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in Requirements R16 and R19.

R14 Each Generator Owner shall transmit the generator underfrequency trip setting and time delay to its Planning Coordinator within 45 days of the Planning Coordinator's request.

R15 Each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard, or an existing generator increasing its net capability by greater than 10% shall

R16 Each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1 shall:

R17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area.

R18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall apply the criteria described in Attachment B to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area.

R19 Each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 1, based on their licensing design basis, shall:

R20 The Planning Coordinator shall update its UFLS program database as specified by the NERC PRC Standard on UFLS. This database shall include the following information: [

R21 Each Planning Coordinator shall notify each Distribution Provider, Transmission Owner, and Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program performance characteristics as specified by the NERC PRC Standard on UFLS.[

R22 Each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R21.

R23 Each Distribution Provider, Transmission Owner and Generator Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21.

The approval process for a regional reliability standard requires NERC to publicly notice and request comment on the proposed standard. Comments shall be permitted only on the following criteria (technical aspects of the standard are vetted through the regional standards development process):

Unfair or Closed Process — The regional reliability standard was not developed in a fair and open process that provided an opportunity for all interested parties to participate. Although a NERC-approved regional reliability standards development procedure shall be presumed to be fair and open, objections could be raised regarding the implementation of the procedure.

Adverse Reliability or Commercial Impact on Other Interconnections — The regional reliability standard would have a significant adverse impact on reliability or commerce in other interconnections.

Deficient Standard — The regional reliability standard fails to provide a level of reliability of the bulk power system such that the regional reliability standard would be likely to cause a serious and substantial threat to public health, safety, welfare, or national security.

Adverse Impact on Competitive Markets within the Interconnection — The regional reliability standard would create a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability.

1. **Was the proposed standard developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?**

   ☐ Yes

   ☐ No

   Comments:

2. **Does the proposed standard pose an adverse impact to reliability or commerce in a neighboring region or interconnection?**

   ☐ Yes

   ☐ No

Comments:

3. **Does the proposed standard pose a serious and substantial threat to public health, safety, welfare, or national security?**

☐ Yes
☐ No

Comments:

4. **Does the proposed standard pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?**

☐ Yes

☐ No

Comments:

5. **Does the proposed regional reliability standard meet at least one of the following criteria?**
   - **The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard**
   - **The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard**
   - **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

☐ Yes

☐ No

Comments:

Regional Reliability Standards Announcement

Comment Period Open for PRC-006-NPCC-1
November 22, 2011–December 22, 2011

Regional Project: Now Available

Proposed Standard for the Northeast Power Coordinating Council (NPCC)

NPCC has requested NERC to post regional reliability standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding for a 30-day industry review as permitted by the NERC Rules of Procedure.

Instructions
Please use this **electronic form** to submit comments. If you experience any difficulties in using the electronic form, please contact Eleanor Crouch at **eleanor.crouch@nerc.net**. An off-line, unofficial copy of the comment form is posted on the **regional standards development page**:

Background
PRC-006-NPCC-1 ensures the development of an effective Automatic Underfrequency Load Shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events.

Regional Reliability Standards Development Process
Section 300 of the ***Rules of Procedure for the Electric Reliability Organization*** governs the regional reliability 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 Eleanor Crouch at **eleanor.courch@nerc.net** (via email) or at 404.446.2572.

Exhibit C

Standard Drafting Team Roster

Regional Standard PRC-006-NPCC-1 Automatic UFLS
Drafting Team Roster with Biographies

1. Jonathan Appelbaum--- United Illuminating Company

Mr. Appelbaum holds the position of Director of NERC Compliance at the United Illuminating Company.

Prior to joining UI, Mr. Appelbaum was a Manager at Long Island Power Authority in System Operations where he managed the operational planning and engineering support for transmission system operations. In total he has 21 years of experience in various roles of the electric utility industry including generation, transmission, engineering, automation, and wholesale marketing.

He is familiar with the market and operations procedures at both NYISO, and ISO-NE. He has participated in writing the New York State Reliability Council Rules and assessing compliance to those rules. He has actively participated in the reliability activities of NPCC. In his role in System Operations he was responsible for ensuring compliance with the NPCC criteria for UFLS. He gained experience in applying the details of establishing the UFLS program including how to measure the percentage of load scheduled to be shed, various in feeder loads based on season and the impact on target percentages, scheduling compensating load shed for generators that trip above the target curve, coordinating with generators to change settings to conform with target curves, coordinating with generators on auxiliary equipment relay settings, and assessing compliance of Transmission Owners in New York State to the New York State Reliability Rule requirements for under frequency load shedding. He also participated in the working groups that reviewed the NPCC studies that formed the basis of the current under frequency program.

He has a B.S. in Mechanical Engineering and an MBA.

2. Rich Burke ---ISO-NE (Chairperson):

Principal Analyst, ISO New England Inc. Reliability & Operations Compliance

Richard W. Burke has forty two (42) years of experience in the utility industry. His career began at the Vermont Yankee Nuclear Power Corporation where he performed functions of increasing responsibility over twenty (20) years that included performing as a licensed Senior Operator, serving as the Engineering Department Manager and the Corporate Operations Support Department Manager. Mr. Burke was employed by the Electric Power Research Institute in its Nuclear Power Division for a period of 11 years as a Project Manager and a Program Manager and was a key contributor to EPRI’s Advanced Reactor Development program.

In 2000 he began his employment at ISO New England as an Officer of the NEPOOL Reliability & Tariff Technical Committees transferring to the Reliability & Operations Compliance Group in 2006. Mr. Burke has been charged with the overall responsibility of monitoring New England’s compliance to the NPCC UFLS Criteria since 2004. He has served as a Member of the NPCC Task Force on System Protection and the NPCC Compliance Committee. Mr. Burke is a graduate of the United States Navy Nuclear Power School and served for six (6) years in the Navy’s Nuclear Powered Submarine Program assigned to the Electric Division onboard the U.S.S. Theodore Roosevelt SSB (N) 600.

He holds a Bachelor's degree in Mechanical Engineering from the University of Massachusetts.

3. Stephen Burns ---IESO

Stephen Burns graduated with a B.Sc. (1983) and M. Sc (1985) degrees in electrical engineering from Queen's University, Kingston Ontario. After spending two years at Bruce Nuclear during the commissioning of units at the Bruce B nuclear station, he joined the Power System Operations Division (PSOD) at Ontario Hydro in 1987. From that time to the present, Mr. Burns has conducted operating and planning studies involving the Ontario electricity system. Since 1989 he has worked in various NPCC forums to maintain the reliability of the bulk electricity system. Mr. Burns is a Registered Professional Engineer in the Province of Ontario.

4. Edward F. Dahill--- National Grid

Mr. Dahill has 40 years electric power industry experience with a diverse background of engineering, financial and management responsibilities from working for electric utilities, utility consulting firms and a major industrial entity. He has a record of implementing utility regulatory policies and practices, providing rate case testimony and involvement with non-traditional utility ventures.
Mr. Dahill received his Bachelor of Electrical Engineering Degree from Merrimack College with Masters Degrees from Northeastern University in both Electrical Engineering (Power Option) and Business Administration. He is a licensed professional electrical engineer in the Commonwealth of Massachusetts.
Mr. Dahill's recent primary responsibilities have been associated with the National Grid programs for compliance with the NERC and NPCC Reliability Compliance Enforcement Programs, including National Grid's implementation of NPCC's Directory #12 for Underfrequency Load Shedding. His responsibilities include researching and coordinating National Grid's reliability compliance reporting for NPCC, ISO-NE and NYISO requirements.
Mr. Dahill has represented National Grid on various NERC, NPCC, ISO-NE and NYISO committees, including both the NERC Compliance and Certification Committee and the NPCC Compliance Committee.

5. Carey Fleming--- Constellation

Carey Fleming is in-house nuclear counsel for Constellation Energy Nuclear Group, LLC ("CENG"). CENG operates five nuclear units at the following three sites: Calvert Cliffs (in Maryland), Nine Mile Point (north of Syracuse, NY), and R.E. Ginna (north of Rochester, NY). Mr. Fleming's responsibilities for these nuclear plants focus in the areas of nuclear licensing, administrative law, and regulatory compliance. These duties include providing the company with legal and regulatory analysis and strategy related to CENG's: 1) existing nuclear units; and, 2) potential nuclear acquisitions of existing nuclear facilities owned by others. Prior to joining Constellation in January 2005, Mr. Fleming was an associate in the Washington, DC, office of Winston & Strawn, LLP, providing counsel to clients in the areas of U.S. Nuclear Regulatory Commission ("NRC") regulatory matters.

Before becoming an attorney and joining Winston & Strawn, Mr. Fleming obtained approximately 16 years of experience operating and working at a commercial nuclear facility. While with the utility, Mr. Fleming held an NRC Senior Reactor Operator ("SRO") license for 11 of those years and worked in the areas of control room operations, classroom and simulator training, root-cause investigation, and regulatory affairs. Mr. Fleming served as a submarine nuclear propulsion plant operator in the U.S. Navy Nuclear Propulsion Program for six years prior to joining the utility.

Mr. Fleming is a summa cum laude graduate of North Carolina Wesleyan College with a B.S. in Computer Information Systems. He received his J.D., cum laude, from North Carolina Central University School of Law, where he was a member of the law journal.
Mr. Fleming is a member of the Bar of the District of Columbia.

6. Robert Giguere--- Entergy

Robert Giguere attended the University of Michigan, served in the U.S. Navy as an electrician and has fourteen years of experience in commercial power plant operations and engineering. During the last four years, Mr. Giguere has worked as an Entergy Nuclear corporate representative for FERC/NERC interface. He has participated in both SERC and NPCC audits and committees. Mr. Giguere has worked with both ISO-NE and NYISO as a member of joint nuclear committees.

7. Brian Evans- Mongeon--- Utility Services

Brian Evans-Mongeon is the President and CEO of Utility Services, Inc., a service firm formed in 2007, specializing in assisting registered entities in the Electric Reliability Organization (ERO) program.

As the President and CEO of Utility Services, he is responsible for oversight of ERO Compliance and Monitoring for client's in regions across the U.S.; ISO & NEPOOL markets; and Renewable Energy Trading and associated activities.

Utility Services is a member in five of the eight NERC regions and its' staff hold a number of committee positions within those regions. Brian is a member of NPCC's Compliance and Regional Standards Committee, and is a participant in the NPCC task force for regional standards on disturbance monitoring.

At NERC, Brian is a participant in the Standard Drafting Team for the Under Frequency Load Shedding program (NERC Project 2007-1), is currently a member of the Definition of Bulk Electric System (BES) team (NERC Project 2010-17), and is the current chair of the Standard Drafting Team for Disturbance and Sabotage Reporting (NERC Project 2009-01). Previously, Brian has over twenty years of experience in the electrical utility business working for both Green Mountain Power Corporation as a Power Operations & Administration Manager and Vermont Public Power Supply Authority as a Marketing Services Manager.

8. Si Truc Phan--- Hydro Quebec TransEnergie

Mr. Phan holds a Bachelors Degree in Power Engineering from the Institute of Technology Superior (Ecole de Technologie Supérieure, Montreal, Canada 1992)

TransEnergie; Hydro-Quebec since 1992
Planning and Operating Strategies for the Main Transmission System (18 yrs)
Responsible of the UFLS program for Quebec Interconnection (since 2003)

Responsible of Black Start Restoration Strategies (since 1999)
Responsible of Y2K Study and Strategy for the Main Transmission System (2000)
Responsible of Reliability Standard for the Reliability Coordinator in Quebec (since 2010).
NERC:
Member of Major System Disturbance Task Force for the August 14th 2003 Blackout. (2003)
Member of NERC UFLS Drafting Team (since 2007)

NPCC:
Member Dynamics System Study SS-38 Committee (since 1999)
Member of Regional UFLS Standard Drafting Team (since 2008)
Member of Regional Standard Committee (since 2010)

9. Anie Philip ---LIPA

Ms. Philip joined National Grid in 2003 and has been representing and working on behalf of Long Island Power Authority.

She worked as a transmission planning engineer until September, 2009 and as a Lead Engineer in System Operations until September 2011.

At present, she is the manager of the Transmission Planning. She received a B.S. in Electrical engineering from State University of New York at Stony Brook in 2002 and M.S. in Electrical Engineering from Columbia University in 2008. She is also a NYS licensed Professional Engineer.

10. Jeremiah Stevens---NYIS0

Education: B.S.E.E., M.S.E.E.
Licenses/Certifications: Professional Engineer (New York)

At the time PRC-006-NPCC-01 was written, Mr. Stevens was employed by the New York Independent System Operator.

Brief Description of Experience Relevant to PRC-006-NPCC-01:

Responsible for the UF tripping data collection from entities within the New York Control Area.

11. Jason Savulak----Hydro One

Masters and Bachelor of Science in Electrical engineering from the University of Waterloo.

Mr. Savulak has been working for Hydro One, the primary transmission company in Ontario for approximately 8 years. He works in Operations dealing mostly with system assessments and providing real-time technical analysis and support.

12. Khin Swe ---NYPA

Khin T. M. Swe joined NYPA Transmission Planning Department as a System Planning Engineer in 2006. Performed various system studies such as: Wind Farms Combined Effect on the 230kV

Transmission System of North Eastern NY; Alternative NYPA Plan of Under Frequency Load Shedding (for NPCC Directory 12); SPS classifications and impact studies, and classification tests for Bulk Power System (BPS) elements (NPCC A-10). The studies involved performing load flow, voltage drop and stability studies. She evaluates System Reliability Impact Studies (SRIS) for those projects requesting to connect to NYPA Transmission System. She represents NYPA on NPCC Task Force on System Studies (TFSS). She was a member on NPCC Inter-Area Dynamic Analysis Working Group (SS-38) presenting NYPA. Prior to NYPA, she worked for Washington Group International (formerly Ebasco or Raytheon Engineers & Constructors, New York, NY). She performed many power system studies and substation control design on various utilities projects. She completed her BSEE in 1980 and MSEE in 1984 from the Polytechnic Institute of New York. She is a member of IEEE, engineering honor society Tau Beta Pi and Eta Kappa Nu.

13. Dan Taft ---Consolidated Edison Company of NY

Mr. Taft holds a Bachelor of Engineering in Electrical Engineering from Stevens Institute of Technology in Hoboken, NJ (May 1979) and a Master of Engineering in Electric Power Engineering from Rensselaer Polytechnic Institute in Troy, NY (May 1990)

Mr. Taft began his career with General Electric in 1979 in the area of Protective Relaying, then moved on to Hubbell, Incorporated in 1985 to work on Ground Fault Interrupters and Surge Suppressors. After earning a Master's degree in the field of Electric Power Engineering, he went to work for Con Edison in 1990, again in the area of Protective Relaying. He became a Senior System Operator in the Con Edison's Control Center in 2003. In 2006, he became a Section Manager in Con Edison's Transmission Planning Dept. In 2009, he took a position at the Federal Energy Regulatory Commission in the Office of Electric Reliability, and returned to Con Edison in 2011 as a Section Manager of the Operations Analysis Group in the System Operation Dept.

14. Mohsen Zam Zam---Consolidated Edison Company of NY

Mr. Zam has worked in the utility business for over twenty five years. Most of his career has been devoted to planning and evaluating the transmission and the performance of the Bulk power system.

He is member of the NPCC System Studies SS-38 group responsible for evaluating the adequacy of the Under Frequency Load Shedding (UFLS) protection schemes.He also plans and determines the stages and the frequency settings for the Con Edison's UFLS scheme in accordance with the NPCC standards. He participated in the simulations and re-creation of the August 14, 2003 Blackout events.

Mr. Zam coauthored an IEEE paper with PTI personnel on system restoration including the development of eight restoration plans to restore the Con Edison system following a total system shutdown with and without external help. He evaluates new technology and new energy sources such as HVDC, Wind Mill generators, FACT devices and VFT and determines their impact on the bulk power transmission system.

He was involved with the installation of Phasor Measuring Units (PMU) on the transmission system for system operation wide area visualization. He was also involved in investigating the implementation of the Synchro-phasor technology for monitoring the Bulk Power System for the entire Eastern seaport electric grid.

15. Guy Zito ---NPCC

Education: B.S.E.E., PTI Licenses/Certifications

Employer at the time PRC-006-NPCC-01 was written: Northeast Power Coordinating Council

Brief Description of Experience Relevant to PRC-006-NPCC-01:

Planning and Operating experience of Transmission and Distribution systems, reviewed system disturbances and the data required to properly analyze and mitigate those occurrences.

13. Lee Pedowicz ---NPCC

Education: B.S.E.E., M.S.--Electric Power Engineering, G.E. Power Systems Engineering Course
Licenses/Certifications: Professional Engineer (New York), NERC Reliability Operator

Employer at the time PRC-006-NPCC-01 was written: Northeast Power Coordinating Council

Brief Description of Experience Relevant to PRC-006-NPCC-01:

Bulk and Distribution Power System Operations which utilized UFLS equipment as a last resort to maintain system security.

14. Gerry Dunbar---NPCC

Education: B.A. Economics, Siemens Power Technology Course
Licenses/Certifications:

Employer at the time PRC-006-NPCC-01 was written: Northeast Power Coordinating Council
Brief Description of Experience Relevant to PRC-006-NPCC-01:

Thirty years of power system operations experience which included assignments as a qualified bulk power substation operator, instructor substation operations, control room operator (transmission and distribution operations).

Exhibit D

PRC-006-NPCC-1 Violation Severity Level and Violation Risk Factor Analysis

NPCC Regional UFLS Standard PRC-006-NPCC-1
VRF and VSL Justification

This document provides the justification for assignment of VRFs and VSLs, identifying how each proposed VRF and VSL meets NERC's criteria and FERC's Guidelines. NERC's criteria for setting VRFs and VSLs; FERC's five guidelines (G1 – G5) for approving VRFs; and FERC's four guidelines (G1-G4) for setting VSLs are provided at the end of this document.

VRF and VSL Justifications		
R1	Proposed VRF	Medium
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This requirement in the proposed standard determines the UFLS programs to respond to islanding situations and compensatory load shedding, and has been assigned a Medium Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards The requirements in PRC-006-NPCC-1 Automatic Underfrequency Load Shedding that pertain to the determination of islands have been assigned a Medium Violation Risk Factor, consistent with the VRF assignments in PRC-006-1.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The Medium VRF assignment is consistent with the NERC definition in that it is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed Requirement is referred to in Requirement R3. Requirement R1 has the higher Medium VRF. Requirement R3 has been assigned a Low VRF. The proposed Requirement is referred to in Requirement R6. Requirement R1 has the higher Medium VRF. Requirement R6 has been assigned a High VRF, and is not diminished by this VRF assignment.
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs. or Did not establish requirements for compensatory load shedding.
	Proposed Severe VSL	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs and did not establish requirements for compensatory load shedding.

	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Requirements R1 in PRC-006-1 and PRC-006-NPCC-1 each address a Planning Coordinator's responsibility for determining system islanding. Lower: Not applicable in PRC-006-1 and PRC-006-NPCC-1. Moderate: Not applicable in PRC-006-NPCC-1, but does not lower the level of compliance. PRC-006-1 assigned a Moderate VSL for a Planning Coordinator failed to consider historical events, or developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands. High: PRC-006-1 assigned a High VSL for a Planning Coordinator failing to consider historical events, or developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. PRC-006-NPCC-1 is more stringent in that it considers the impact of a Planning Coordinator not establishing the requirements for entities aggregating their UFLS programs, or did not establish the requirements for compensatory load shedding. Severe: PRC-006-1 assigned a Severe VSL for a Planning Coordinator failing to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. PRC-006-NPCC-1 is more stringent in that it considers the impact of a Planning Coordinator not establishing the requirements for entities aggregating their UFLS programs, and not establishing the requirements for compensatory load shedding.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL is not binary and does not violate this guideline. Guideline 2b: The VSL is gradated properly. The violation gradations do not overlap.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.

	Requirement	
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

VRF and VSL Justifications		
R2	Proposed VRF	Medium
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This requirement in the proposed standard pertains to the time for the Planning Coordinator to identify to the Regional Entity generation facilities to support the UFLS program characteristics, and has been assigned a Medium Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards The requirements in PRC-006-NPCC-1 Automatic Underfrequency Load Shedding that pertain to the determination of islands have been assigned a Medium Violation Risk Factor, consistent with the VRF assignments in PRC-006-1.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The Medium VRF assignment is consistent with the NERC definition in that it is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation Not applicable.
	Proposed Lower VSL	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 30 days but less than 41 days after completion of the system studies.
	Proposed Moderate VSL	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 40 days but less than 51 days after completion of the system studies.
	Proposed High VSL	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 50 days but less than 61 days after completion of the system studies.
	Proposed Severe VSL	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 60 days after completion of the system studies.

		or The Planning Coordinator did not identify the generation facilities within its Planning Coordinator Area necessary to support the UFLS program.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Requirement R2 in PRC-006-NPCC-1 addresses a Planning Coordinator's responsibility for identifying to the Regional Entity the generation facilities within its Area necessary to support the UFLS program performance characteristics. Requirements R3 and R4 in PRC-006-1 specify the generation by facility nameplate rating. Lower: Not applicable in PRC-006-1 R3, but R4 assigned a Lower VSL for a failure to include one of the items listed in its Parts 4.1 through 4.7 in a UFLS assessment, which includes the generation specification. PRC-006-NPCC-1 addresses a delay in the identification of generation facilities within its Planning Coordinator Area more than 30 days, but less than 41 days after the completion of the system studies. The current level of compliance is not lowered. Moderate: PRC-006-1 R3 assigned a Moderate VSL for a Planning Coordinator failing to meet one of the performance characteristics specified in Part s 3.3.1, 3.3.2, and 3.3.3 addressing generation. PRC-006-1 R4 assigned a Moderate VSL for a failure to include two of the items listed in Parts 4.1 through 4.7. PRC-006-NPCC-1 addresses a delay in the identification of generation facilities within its Planning Coordinator Area more than 40 days, but less than 51 days after the completion of the system studies. The current level of compliance is not lowered. High: PRC-006-1 R3 assigned a High VSL for a Planning Coordinator failing to meet two of the performance characteristics specified in Parts 3.3.1, 3.3.2, and 3.3.3 addressing generation. PRC-006-1 R4 assigned a High VSL for a failure to include three of the items listed in Parts 4.1 through 4.7. PRC-006-NPCC-1 addresses a delay in the identification of generation facilities within its Planning Coordinator Area more than 50 days, but less than 61 days after the completion of the system studies. The current level of compliance is not lowered. Severe: PRC-006-1 R3 assigned a Severe VSL for a Planning Coordinator failing to meet all of the performance characteristics specified in Parts 3.3.1, 3.3.2, and 3.3.3 addressing generation, or failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area. PRC-006-1 R4 assigned a Severe VSL for a failure to include four or more of the items listed in Parts 4.1 through 4.7, or failure to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. PRC-006-NPCC-1 addresses a delay in the identification of generation facilities within its Planning Coordinator Area more than 60 days after the completion of the system studies, or the Planning Coordinator did not identify the generation facilities within its Planning Coordinator Area necessary to support the UFLS program. The current level of compliance is not lowered.
	FERC VSL G2 Violation Severity Level Assignments Should	Guideline 2a-- the VSL is not binary and does not violate this guideline. Guideline 2b--the VSL does not contain ambiguous language.

	Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.
VRF and VSL Justifications		
R3	Proposed VRF	Lower
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This Requirement in the proposed standard pertains to time requirements for submitting information and has been assigned a Lower Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. The requirements in PRC-006-1 do not have a time deadline requirement for providing information to Transmission Owners, Distribution Providers, and Generator Owners.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs This Requirement has a Lower VRF because it is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed Requirement refers to Requirement R1 which has a Medium

		VRF. This Requirement has been assigned a Low VRF because it addresses the time to submit information, and does not diminish the Medium VRF for R1.
	Proposed Lower VSL	The Planning Coordinator provided the requested information, but did so more than 30 days but less than 41 days to the requesting entity.
	Proposed Moderate VSL	The Planning Coordinator provided the requested information, but did so more than 40 days but less than 51 days to the requesting entity.
	Proposed High VSL	The Planning Coordinator provided the requested information, but did so more than 50 days but less than 61 days to the requesting entity.
	Proposed Severe VSL	The Planning Coordinator provided the requested information, but did so more than 60 days after the request. or The Planning Coordinator failed to provide the requested information.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirements in PRC-006-1 do not have a time deadline requirement for providing information to Transmission Owners, Distribution Providers, and Generator Owners. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a-- the VSL is not binary and does not violate this guideline. Guideline 2b--the VSL does not contain ambiguous language.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

VRF and VSL Justifications		
R4	Proposed VRF	High
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report Protection systems and their coordination.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This Requirement in the proposed standard pertains to the implementation of an automatic UFLS program and has been assigned a High Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards The requirements in PRC-006-NPCC-1 Automatic Underfrequency Load Shedding that pertains to the implementation of automatic tripping of load has been assigned a High Violation Risk Factor, consistent with the VRF assignment in PRC-006-1.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed Requirement is referred to in R5. Both Requirements have been assigned a High VRF.
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A
	Proposed Severe VSL	The Distribution Provider or Transmission Owner failed to implement an automatic UFLS program reflecting normal operating conditions excluding outages, for its Facilities or collectively implemented by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on frequency thresholds, total nominal operating time, and amounts specified in the appropriate included tables.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Requirement R9 in PRC-006-1 addresses the tripping of load for automatic UFLs programs. Lower: Not applicable in PRC-006-NPCC-1. PRC-006-1 assigned a Lower VSL to an entity for providing less than 100% but more than 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets. . Moderate: Not applicable in PRC-006-NPCC-1. PRC-006-1 assigned a Moderate VSL to an entity for providing less than 95% but more than 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.

		High: Not applicable in PRC-006-NPCC-1. PRC-006-1 assigned a High VSL to an entity for providing less than 90% but more than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets. Severe: PRC-006-NPCC-1 assigns a Severe VSL for a Distribution Provider or Transmission Owner failing to implement an automatic UFLS program as described in the Standard. PRC-006-1 assigned a Severe VSL to an entity for providing less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a-- the VSL is binary and does not violate this guideline. This requirement has a Severe VSL assigned. Guideline 2b-- the VSL does not contain ambiguous language.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

VRF and VSL Justifications		
R5	Proposed VRF	High
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report Protection systems and their coordination.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This Requirement in the proposed standard pertains to the implementation of an automatic UFLS program and has been assigned a High Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards PRC-006-1 Requirement R12 mandates a UFLS design assessment if event assessment program deficiencies are identified, and has a Medium VRF. PRC-006-NPCC-1 Requirement R5 addresses exceeding tolerances and deviations with a High VRF, which is consistent with the NERC definition of a High VRF.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed Requirement refers to elements in Requirement R4. Both Requirements have been assigned a High VRF.
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not inform the Planning Coordinator of the need to exceed the stated tolerances of UFLS Table 2 or Table 3, and in the case of Table 2 only, the need to deviate from providing two stages of UFLS.
	Proposed High VSL	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not provide the Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with the appropriate table.
	Proposed Severe VSL	The Distribution Provider or Transmission Owner did not arm its load to trip on underfrequency in order to meet its minimum obligations and in doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load.

	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-006-1 Requirement R12 mandates a UFLS design assessment if event assessment program deficiencies are identified. Lower: Not applicable in PRC-006-NPCC-1, nor PRC-006-1. Moderate: PRC-006-NPCC-1 assigned a Moderate VSL to an entity if it exceeded tolerances and/or deviated from the number of stages and frequency setpoints of the UFLS program, and did not inform the Planning Coordinator of the need to exceed the stated tolerances. PRC-006-1 addresses the failure of a Planning Coordinator to conform to the consideration of identified deficiencies greater than two years but less than or equal to 25 months of event actuation. High: PRC-006-NPCC-1 assigned a High VSL to an entity if it exceeded tolerances and/or deviated from the number of stages and frequency setpoints of the UFLS program, and did not provide the Planning Coordinator with an analysis demonstrating alternative solutions. PRC-006-1 addresses the failure of a Planning Coordinator to conform to the consideration of identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation. Severe: PRC-006-NPCC-1 assigned a Severe VSL to an entity if it did not arm its load to trip on Underfrequency and exceeded tolerances and/or deviated from the number of stages and frequency setpoints of the UFLS program. PRC-006-1 addresses the failure of a Planning Coordinator to conform to the consideration of identified deficiencies greater than 26 months of event actuation, or the Planning Coordinator with deficiencies failed to conduct and document a UFLS design assessment to consider the identified deficiencies. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a-- the VSL is not binary and does not violate this guideline. Guideline 2b--the VSL does not contain ambiguous language.
	FERC VSL G3 Violation Severity Level	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.

	Assignment Should Be Consistent with the Corresponding Requirement	
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.
VRF and VSL Justifications		
R6	Proposed VRF	High
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report Protection systems and their coordination. This Requirement pertains to the Quebec Interconnection.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This Requirement in the proposed standard pertains to the implementation of an automatic UFLS program and has been assigned a High Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards PRC-006-NPCC-1 addresses the implementation of an automatic UFLS program in the Quebec Interconnection, with a High VRF. Section E Regional Variances of PRC-006-1addresses the Regional Variances for the Quebec Interconnection. Requirements E.A.3, and E.A. 4 addressing the Quebec Interconnection automatic UFLS program each have been assigned a High VRF.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed Requirement has been assigned a High VRF, and refers to elements in Requirement R1. Requirement R1 has been assigned a Medium VRF because it deals with the establishment of aggregating UFLS programs. This Requirement's VRF assignment is not diminished.
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A
	Proposed Severe VSL	The Distribution Provider or Transmission Owner in the Québec Interconnection portion of NPCC did not implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total

		nominal operating time and amounts specified in Attachment C, Table 4 or did not collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Section E Regional Variances of PRC-006-1addresses the tripping of load for automatic UFLs programs in the Quebec Interconnection. Lower: Not applicable in PRC-006-NPCC-1. PRC-006-1 assigned a Lower VSL to an entity for providing less than 100% but more than 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets. Moderate: Not applicable in PRC-006-NPCC-1. PRC-006-1 assigned a Moderate VSL to an entity for providing less than 95% but more than 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets. High: Not applicable in PRC-006-NPCC-1. PRC-006-1 assigned a High VSL to an entity for providing less than 90% but more than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets. Severe: PRC-006-NPCC-1 assigns a Severe VSL for a Distribution Provider or Transmission Owner failing to implement an automatic UFLS program as described in the Standard. PRC-006-1 assigned a Severe VSL to an entity for providing less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a-- the VSL is binary and does not violate this guideline. This requirement has a Severe VSL assigned. Guideline 2b-- the VSL does not contain ambiguous language.

	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.
VRF and VSL Justifications		
R7	Proposed VRF	High
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report Protection systems and their coordination.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This Requirement in the proposed standard pertains to the implementation of an automatic UFLS program have been assigned a High Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards The requirements in PRC-006-1 do not address specific time delay parameters.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation Not applicable.
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A
	Proposed Severe VSL	The Distribution Provider or Transmission Owner failed to set an underfrequency relay that is part of its region's UFLS program as specified in Requirement R7.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current	The requirements in PRC-006-1 do not specify time delay parameters. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance.

	Level of Compliance	
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a-- the VSL is binary and does not violate this guideline. This requirement has a Severe VSL assigned. Guideline 2b-- the VSL does not contain ambiguous language.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.
VRF and VSL Justifications		
R8	Proposed VRF	Medium
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This Requirement in the proposed standard pertains to the development and review inhibit threshold settings, and is assigned a Medium Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards This Requirement pertains to the development and review of inhibit threshold settings. These settings are not addressed in PRC-006-1.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs This Requirement has a Medium VRF because it is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or

		restore the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation Not applicable.
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	The Planning Coordinator developed inhibit thresholds as specified in Requirement R8 but did not perform the review once per calendar year.
	Proposed Severe VSL	The Planning Coordinator did not develop inhibit thresholds as specified in Requirement R8.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirements in PRC-006-1 do not address the development and review of inhibit threshold settings. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a-- the VSL is not binary and does not violate this guideline. Guideline 2b--the VSL does not contain ambiguous language.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

VRF and VSL Justifications		
R9	Proposed VRF	Medium
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This Requirement in the proposed standard pertains to providing inhibit thresholds, and is assigned a Medium Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards This Requirement pertains to the providing of inhibit threshold settings to the Transmission Owner and Distribution Provider. This is not addressed in PRC-006-1.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs This Requirement has a Medium VRF because it is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed Requirement is referred to in Requirement R10. Requirement R10 has a High VRF. This requirement has been assigned a Medium VRF because it addresses the time to submit information, and does not diminish the High VRF for R10. The proposed Requirement is referred to in Requirement R11. Requirement R11 has a Lower VRF because it addresses the time for the submission of an implementation plan. This requirement is not diminished by the Requirement R11 Lower VRF..
	Proposed Lower VSL	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 30 days but less than 41 days of the initial determination or any subsequent change to the inhibit thresholds.
	Proposed Moderate VSL	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 40 days but less than 51 days of the initial determination or any subsequent change to the inhibit thresholds.
	Proposed High VSL	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 50 days but less than 61 days of the initial determination or any subsequent change to the inhibit thresholds.
	Proposed Severe VSL	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 60 days after the initial determination or any subsequent change to the inhibit thresholds. or The Planning Coordinator did not provide to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds.

	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirements in PRC-006-1 do not address the providing of inhibit thresholds to the Transmission Owner and Distribution Provider. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a-- the VSL is not binary and does not violate this guideline. Guideline 2b--the VSL does not contain ambiguous language.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.
VRF and VSL Justifications		
R10	Proposed VRF	High
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report Protection systems and their coordination.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This Requirement in the proposed standard pertains to the implementation of the inhibit threshold settings, and is assigned a High Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards This Requirement pertains to the implementation of inhibit threshold settings by the Transmission Owner and Distribution Provider. This is not addressed

		in PRC-006-1.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed Requirement refers to Requirement R9 which has a Medium VRF. This Requirement has been assigned a High VRF because it addresses implementing the inhibit threshold settings specified in Requirement R9, and its High VRF is not diminished.
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A
	Proposed Severe VSL	The Distribution Provider or Transmission Owner did not implement the inhibit threshold based on the notification provided by the Planning Coordinator in accordance with Requirement R9.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirements in PRC-006-1 do not address the implementation of inhibit threshold settings. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a-- the VSL is binary and does not violate this guideline. This requirement has a Severe VSL assigned. Guideline 2b-- the VSL does not contain ambiguous language.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.

	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.
VRF and VSL Justifications		
R11	Proposed VRF	Lower
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This Requirement in the proposed standard pertains to the time for submitting an implementation of the inhibit threshold settings, and is assigned a Lower Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards This Requirement pertains to the development and submission of an implementation plan in accordance with R9 for inhibit thresholds. This is not addressed in PRC-006-1.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs This Requirement has a Lower VRF because it is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed Requirement refers to Requirement R9 which has a Medium VRF. This Requirement has been assigned a Lower VRF because it addresses the time to submit an implementation plan. The Requirement R9 Medium VRF is not diminished.
	Proposed Lower VSL	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.
	Proposed Moderate VSL	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.
	Proposed High VSL	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.
	Proposed Severe VSL	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider or Transmission Owner did not develop its implementation plan.

	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirements in PRC-006-1 do not address the implementation of inhibit threshold settings. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a-- the VSL is not binary and does not violate this guideline. Guideline 2b--the VSL does not contain ambiguous language.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.
VRF and VSL Justifications		
R12	Proposed VRF	Lower
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This Requirement in the proposed standard pertains to the provision of documentation to the Planning Coordinator of the actual net Load that would be shed by the UFLS relays at each stage, and is assigned a Lower Violation Risk Factor.
	FERC VRF G3	Guideline 3- Consistency among Reliability Standards

	Discussion	This Requirement pertains to the provision of documentation to the Planning Coordinator of the actual net Load that would be shed by the UFLS relays at each stage. This is not addressed in PRC-006-1.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs This Requirement has a Lower VRF because it is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation Not applicable.
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A
	Proposed Severe VSL	The Transmission Owner or Distribution Provider did not provide documentation to its Planning Coordinator of actual net load data or updates to the data that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirements in PRC-006-1 do not address the provision of documentation to the Planning Coordinator of the actual net Load by the UFLS relays at each stage. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a-- the VSL is binary and does not violate this guideline. This requirement has a Severe VSL assigned. Guideline 2b-- the VSL does not contain ambiguous language.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.

	Requirement	
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.
VRF and VSL Justifications		
R13	Proposed VRF	High
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report Protection systems and their coordination.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This Requirement in the proposed standard pertains to the setting of generator underfrequency trip relays, and has been assigned a High Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards This requirement pertains to the setting of generator underfrequency trip relays. This is not addressed in PRC-006-1.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed Requirement has been assigned a High VRF, and refers to Requirement R16 (High VRF), and Requirement R19 (High VRF).
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A
	Proposed Severe VSL	The Generator Owner did not set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements in PRC-006-1 do not address the setting of generator underfrequency trip relays. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance.
	FERC VSL G2 Violation Severity Level Assignments Should	Guideline 2a-- the VSL is binary and does not violate this guideline. This requirement has a Severe VSL assigned.

	Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b-- the VSL does not contain ambiguous language.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.
VRF and VSL Justifications		
R14	Proposed VRF	High
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This Requirement in the proposed standard pertains to the transmission of generator underfrequency trip settings and time delays to the Planning Coordinator, and has been assigned a High Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards This requirement pertains to the transmission of generator underfrequency trip settings and time delays to the Planning Coordinator. This is not addressed in PRC-006-1.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The transmitting of this information to the Planning Coordinator is critical to the establishment of an effective automatic UFLS program. Thus the assignment of the High Violation Risk Factor that is High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.

	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation Not applicable.
	Proposed Lower VSL	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 45 days and less than 56 days of the Planning Coordinator’s request.
	Proposed Moderate VSL	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 55 days and less than 66 days of the Planning Coordinator’s request.
	Proposed High VSL	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 65 days and less than 76 days of the Planning Coordinator’s request.
	Proposed Severe VSL	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 75days after the Planning Coordinator’s request. or The Generator Owner did not transmit the generator underfrequency trip setting and time delay to its Planning Coordinator.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirements in PRC-006-1 do not address the transmission of generator underfrequency trip settings and time delays. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a-- the VSL is not binary and does not violate this guideline. Guideline 2b--the VSL does not contain ambiguous language.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.
	FERC VSL G4	The VSL is based on a single violation.

	Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justifications		
R15	Proposed VRF	High
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report Protection systems an d their coordination.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This Requirement in the proposed standard pertains to Generator Owners to design systems to prevent undesired tripping for system conditions above underfrequency trip thresholds, and has been assigned a High Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards This Requirement pertains to Generator Owners to design systems to prevent undesired tripping for system conditions above underfrequency trip thresholds. This is not addressed in PRC-006-1.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation Not applicable.
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	The Generator Owner did not fulfill the obligation of Requirement R15; Part 15.1 OR did not fulfill the obligation of Requirement R15, Part 15.2.
	Proposed Severe VSL	The Generator Owner did not fulfill the obligation of Requirement R15, Part 15.1 and did not fulfill the obligation of Requirement R15, Part 15.2.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirements in PRC-006-1 do not address Generator Owners designing systems to prevent undesired tripping for underfrequency system conditions. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements	Guideline 2a-- the VSL is not binary and does not violate this guideline. Guideline 2b--the VSL does not contain ambiguous language.

	Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

VRF and VSL Justifications		
R16	Proposed VRF	High
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report Protection systems and their coordination.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This Requirement in the posposed standard pertains to Generator Owners of existing non-nuclear units in service that have underfrequency protection set to trip above the appropriate curve in the standard, and has been assigned a High Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards This Requirement pertains to Generator Owners of existing non-nuclear units in service that have underfrequency protection set to trip above the appropriate curve in the standard. This is not addressed in PRC-006-1.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed Requirement is referred to in Requirement R13. Requirement R13 has been assigned a High VRF. This requirement has also been assigned a High VRF. The proposed Requirement (R16.3) is referred to in Requirement R17. Requirement R17 has been assigned a High VRF. This requirement has also

		been assigned a High VRF. The proposed Requirement (R16.3) is referred to in Requirement R18. Requirement R18 has been assigned a High VRF. This requirement has also been assigned a High VRF.
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.2.
	Proposed High VSL	The Generator Owner did not fulfill the obligation of Requirement R16; Part 16.1 OR did not fulfill the obligation of Requirement R16, Part 16.3.
	Proposed Severe VSL	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.1 and did not fulfill the obligation of Requirement R16, Part 16.3.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements in PRC-006-1 do not address Generator Owners of existing non-nuclear units in service that have underfrequency protection set to trip above the appropriate curve in the standard. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a-- the VSL is not binary and does not violate this guideline. Guideline 2b--the VSL does not contain ambiguous language.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of	The VSL is based on a single violation.

	Violations	
VRF and VSL Justifications		
R17	Proposed VRF	High
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This Requirement in the proposed standard pertains to the Planning Coordinators in Ontario, Quebec and the Maritime Provinces for determining compensatory load shedding, and has been assigned a High Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. This Requirement pertains to the Planning Coordinators in Ontario, Quebec and the Maritime Provinces for determining compensatory load shedding. This is not addressed in PRC-006-1.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed Requirement has been assigned a High VRF, and refers to Requirement R16.3 (High VRF).
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A
	Proposed Severe VSL	The Planning Coordinator did not apply the methodology described in Attachment A to determine the compensatory load shedding that is required.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements in PRC-006-1 do not address the Planning Coordinators in Ontario, Quebec and the Maritime Provinces determining compensatory load shedding. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for	Guideline 2a-- the VSL is binary and does not violate this guideline. This requirement has a Severe VSL assigned. Guideline 2b-- the VSL does not contain ambiguous language.

	"Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.
VRF and VSL Justifications		
R18	Proposed VRF	High
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This Requirement in the proposed standard pertains to the Generator Owner, Distribution Provider or Transmission Owner applying criteria to determine compensatory load shedding, and has been assigned a High Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards This Requirement pertains to the Generator Owner, Distribution Provider or Transmission Owner applying criteria to determine compensatory load shedding. This is not addressed in PRC-006-1.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed Requirement has been assigned a High VRF, and refers to Requirement R16.3 (High VRF).
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A

	Proposed High VSL	N/A
	Proposed Severe VSL	The Generator Owner, Distribution Provider, or Transmission Owner did not apply the methodology described in Attachment B to determine the compensatory load shedding that is required.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements in PRC-006-1 do not address the Generator Owner, Distribution Provider or Transmission Owner applying criteria to determine compensatory load shedding. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a-- the VSL is binary and does not violate this guideline. This requirement has a Severe VSL assigned. Guideline 2b-- the VSL does not contain ambiguous language.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

VRF and VSL Justifications		
R19	Proposed VRF	High
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report Protection systems and their coordination.
	FERC VRF G2	Guideline 2- Consistency within a Reliability Standard

	Discussion	This Requirement in the proposed standard pertains to Generator Owners of existing nuclear units in service that have underfrequency protection set to trip above the appropriate curve in the standard, and has been assigned a High Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards This Requirement pertains to Generator Owners of existing nuclear units in service that have underfrequency protection set to trip above the appropriate curve in the standard. This is not addressed in PRC-006-1.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed Requirement is referred to in Requirement R13. Requirement R13 has been assigned a High VRF. This requirement has also been assigned a High VRF.
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.3.
	Proposed High VSL	The Generator Owner did not fulfill the obligation of Requirement R19; Part 19.1 OR did not fulfill the obligation of Requirement R19, Part 19.2.
	Proposed Severe VSL	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.1 and did not fulfill the obligation of Requirement R19, Part 19.2.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements in PRC-006-1 do not address Generator Owners of existing nuclear units in service that have underfrequency protection set to trip above the appropriate curve in the standard. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a-- the VSL is not binary and does not violate this guideline. Guideline 2b--the VSL does not contain ambiguous language.

	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.
VRF and VSL Justifications		
R20	Proposed VRF	Lower
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This Requirement in the proposed standard addresses the Planning Coordinator updating its UFLS program database as specified by PRC-006-1, and has been assigned a Lower Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards This Requirement addresses the Planning Coordinator updating its UFLS program database as specified by PRC-006-1. This Requirement is assigned a Lower Violation Risk Factor. PRC-006-1 Requirements R6, R7, and R8 deal with the UFLS database. Each of those three Requirements has been assigned a Lower Violation Risk Factor.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs This Lower VRF is consistent with the NERC definition because the Requirement is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation Not applicable.
	Proposed Lower VSL	The Planning Coordinator did not have data in its database for one of the parameters listed in Requirement 20, Parts 20.1 through 20.5.
	Proposed Moderate VSL	The Planning Coordinator did not have data in its database for two of the parameters listed in Requirement 20, Parts 20.1 through 20.5.
	Proposed High VSL	The Planning Coordinator did not have data in its database for three of the parameters listed in Requirement 20, Parts 20.1 through 20.5.
	Proposed Severe VSL	The Planning Coordinator did not have data in its database for four or more of the parameters listed in Requirement 20, Parts 20.1 through 20.5.
	FERC VSL G1 Violation Severity Level	This requirement and PRC-006-1 Requirements R6, R7, and R8 all address the UFLS database.

	Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Lower: PRC-006-NPCC-1 Requirement R20 assigned a Lower VSL if the Planning Coordinator did not have data in its database for one of the parameters listed in Requirement 20, Parts 20.1 through 20.5. PRC-006-1 R6 did not assign a Lower VSL. PRC-006-1 R7 assigned a Lower VSL if the Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request. PRC-006-1 R8 assigned a Lower VSL if the UFLS entity provided data to its Planning Coordinator(s) more than 5 calendar days but less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. Moderate: PRC-006-NPCC-1 Requirement R20 assigned a Moderate VSL if the Planning Coordinator did not have data in its database for two of the parameters listed in Requirement 20, Parts 20.1 through 20.5. PRC-006-1 R6 did not assign a Moderate VSL. PRC-006-1 R7 assigned a Moderate VSL if the Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days and up to and including 50 calendar days following the request. PRC-006-1 R8 assigned a Moderate VSL if the UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database, or the UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. High: PRC-006-NPCC-1 Requirement R20 assigned a High VSL if the Planning Coordinator did not have data in its database for three of the parameters listed in Requirement 20, Parts 20.1 through 20.5. PRC-006-1 R6 did not assign a High VSL. PRC-006-1 R7 assigned a High VSL if the Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days and up to and including 60 calendar days following the request. PRC-006-1 R8 assigned a High VSL if the UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. Severe: PRC-006-NPCC-1 Requirement R20 assigned a Severe VSL if the Planning Coordinator did not have data in its database for four or more of the parameters listed in Requirement 20, Parts 20.1 through 20.5. PRC-006-1 R6 assigned a Severe VSL if the Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. PRC-006-1 R7 assigned a Severe VSL if the Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request, or the Planning Coordinator failed to provide its UFLS database to other Planning Coordinators. PRC-006-1 R8 assigned a Severe VSL if the UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database, or the UFLS

		entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. .
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a-- the VSL is not binary and does not violate this guideline. Guideline 2b--the VSL does not contain ambiguous language.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

VRF and VSL Justifications		
R21	Proposed VRF	High
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This Requirement in the proposed standard addresses the Planning Coordinator notifying the Distribution Provider, Transmission Owner, and Generator Owner of changes to load distribution needed to satisfy UFLS program characteristics as specified in NERC PRC-006-1 Requirements R3, and R4, and has been assigned a High Violation Risk Factor.
	FERC VRF G3	Guideline 3- Consistency among Reliability Standards

	Discussion	This Requirement addresses the Planning Coordinator notifying the Distribution Provider, Transmission Owner, and Generator Owner of changes to load distribution needed to satisfy UFLS program characteristics as specified in NERC PRC-006-1 Requirements R3, and R4. This Requirement has been assigned a High Violation Risk Factor. PRC-006-1 Requirements R3, and R4 each have been assigned a High Violation Risk Factor.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed Requirement is referred to in Requirement R22. Requirement R22 has been assigned a High VRF. This requirement has also been assigned a High VRF. The proposed Requirement is referred to in Requirement R23. Requirement R23 has been assigned a Lower VRF because it deals with the time to submit an implementation in accordance with Requirement R21. This Requirement has been assigned a High VRF, and is not diminished by the R23 Lower VRF.
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A
	Proposed Severe VSL	The Planning Coordinator did not notify a Distribution Provider, Transmission Owner, or Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program requirements.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This Requirement and PRC-006-1 R3, and R4 address notifications of load distribution needed to satisfy UFLS program performance characteristics. Lower: Not applicable in PRC-006-NPCC-1 R21. Not applicable in PRC-006-1 R3. PRC-006-1 R4 assigned a Lower VSL if the Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characterisitics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one of the items as specified in Requirement R4, Parts 4.1 through 4.7. Moderate: Not applicable in PRC-006-NPCC-1 R21. PRC-006-1 R3 assigned a Moderate VSL if the Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance=[(load-actual generation output)/(load)], of up to 25 percent within the identified island(s), but failed to meet one of the performance characteristics in Requirement R3, Parts 3.1,

		3.2, or 3.3 in simulations of underfrequency conditions. PRC-006-1 R4 assigned a Moderate VSL if the Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two of the items as specified in Requirement R4, Parts 4.1 through 4.7. High: Not applicable in PRC-006-NPCC-1 R21. PRC-006-1 R3 assigned a High VSL if the Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance=[(load-actual generation output)/(load)], of up to 25 percent within the identified island(s), but failed to meet two of the performance characteristics in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions. PRC-006-1 R4 assigned a High VSL if the Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three of the items as specified in Requirement R4, Parts 4.1 through 4.7. Severe: PRC-006-NPCC-1 R21 assigned a Severe VSL if the Planning Coordinator did not notify a Distribution Provider, Transmission Owner, or Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program requirements. PRC-006-1 R3 assigned a Severe VSL if the Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance=[(load-actual generation output)/(load)], of up to 25 percent within the identified island(s), but failed to meet all the performance characteristics in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions, or the Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area. PRC-006-1 R4 assigned a Severe VSL if the Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include four or more of the items as specified in Requirement R4, Parts 4.1 through 4.7, or the Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a-- the VSL is binary and does not violate this guideline. This requirement has a Severe VSL assigned. Guideline 2b-- the VSL does not contain ambiguous language.

	Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.
VRF and VSL Justifications		
R22	Proposed VRF	High
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report Protection systems and their coordination.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This Requirement in the proposed standard addresses the Distribution Provider, Transmission Owner, and Generator Owner implementing load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R21, and has been assigned a High Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards This Requirement addresses the Distribution Provider, Transmission Owner, and Generator Owner implementing the load distribution changes based on the notification provided by the Planning Coordinator. This Requirement has been assigned a High Violation Risk Factor. This is not addressed in PRC-006-1.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The High VRF assignment is consistent with the NERC definition in that if the requirement is violated, it could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed Requirement has been assigned a High VRF, and refers to

		Requirement R21which has been assigned a High VRF.
	Proposed Lower VSL	N/A
	Proposed Moderate VSL	N/A
	Proposed High VSL	N/A
	Proposed Severe VSL	The Distribution Provider, Transmission Owner, or Generator Owner did not implement the load distribution changes based on the notification provided by the Planning Coordinator.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements in PRC-006-1 do not address the Distribution Provider, Transmission Owner, and Generator Owner implementing the load distribution changes based on the notification provided by the Planning Coordinator. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a-- the VSL is binary and does not violate this guideline. This requirement has a Severe VSL assigned. Guideline 2b-- the VSL does not contain ambiguous language.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.
VRF and VSL Justifications		
R23	Proposed VRF	Lower
	NERC VRF Discussion	

	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard This Requirement in the proposed standard addresses the Distribution provider, Transmission Owner and Generator developing and submitting an implementation plan within 90 days of a request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21, and has been assigned a Lower Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards This Requirement addresses the Distribution Provider, Transmission Owner and Generator developing and submitting an implementation plan within 90 days of a request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21. This Requirement has been assigned a High Violation Risk Factor. This is not addressed in PRC-006-1.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs This Lower VRF is consistent with the NERC definition because the Requirement is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed Requirement has been assigned a Lower VRF, and refers to Requirement R21which has been assigned a High VRF.
	Proposed Lower VSL	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.
	Proposed Moderate VSL	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.
	Proposed High VSL	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.
	Proposed Severe VSL	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider. Transmission Owner or Generator Owner did not develop its implementation plan.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements in PRC-006-1 do not address the Distribution Provider, Transmission Owner and Generator developing and submitting an implementation plan within 90 days of a request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21. The VSL assignments in PRC-006-NPCC-1 do not lower the current level of compliance.
	FERC VSL G2 Violation Severity Level	Guideline 2a-- the VSL is not binary and does not violate this guideline.

	Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b--the VSL does not contain ambiguous language.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding Requirement. It does not expand upon what is in the Requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

NERC's VRF Criteria:

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC's VRF Guidelines:
VRF G1 – Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. From footnote 15 of the May 18, 2007 Order, FERC's list of critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System includes:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

VRF G2 – Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

VRF G3 – Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

VRF G4 – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

VRF G5 –Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC's Criteria for VSLs:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC's VSL Guidelines:
VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance (Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.)

VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties (A violation of a "binary" type requirement must be a "Severe" VSL. Avoid using ambiguous terms such as "minor" and "significant" to describe noncompliant performance.)

VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement (VSLs should not expand on what is required in the requirement.)

VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations (. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.)