NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Standards Committee Conference Call

April 17, 2019 | 1:00 — 3:00 p.m. Eastern Time

Dial-in: 1-415-655-0002 | Access Code: 736 472 453 | Meeting Password: 041719
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Introduction and Chair's Remarks

NERC Antitrust Compliance Guidelines and Public Announcement*
NERC Participant Conduct Policy

Agenda Items

1. **Review April 17 Agenda — Approve** (A. Gallo) (1 minute)
2. **Consent Agenda — Approve** (A. Gallo) (5 minutes)
   a. March 20, 2019 Standards Committee Meeting Minutes* — **Approve**
3. **Projects Under Development — Review**
   a. Project Tracking Spreadsheet (C. Yeung) (5 minutes)
   b. Projected Posting Schedule (H. Gugel) (5 minutes)
4. **Project 2018-04 Modifications to PRC-024-2*— Authorize** (S. Kim) (15 minutes)
5. **Project 2019-01 Modifications to TPL-007-3 Standard Drafting Team Recommendation* CONFIDENTIAL — Appoint** (S. Kim) (15 minutes)
6. **Project 2018-03 Standards Efficiency Review Retirements* — Inform** (S. Kim) (15 minutes)
7. **Legal Update and Upcoming Standards Filings* — Review** (M. Hecht) (5 minutes)
8. **Informational Items — Enclosed**
   a. Standards Committee Expectations*
   b. 2019 Meeting Dates and Locations
   c. 2019 Standards Committee Roster
   d. Highlights of Parliamentary Procedure*
9. **Adjournment**

*Background materials included.

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Antitrust Compliance Guidelines

I. General

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

- Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

III. Activities That Are Permitted

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

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Public Announcements

Conference call:
Participants are reminded that this conference call is public. The access number was posted on the NERC website and widely distributed. Speakers on the call should keep in mind that the listening audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.

Minutes
Standards Committee Meeting

March 20, 2019 | 10:00 a.m. – 3:00 p.m. Central

A. Gallo, chair, called to order the meeting of the Standards Committee (SC or the Committee) on February 20, at 10:00 a.m. Central Time. C. Larson called roll and determined the meeting had a quorum. The SC member attendance and proxy sheets are attached as Attachment 1.

NERC Antitrust Compliance Guidelines and Public Announcement
The Committee secretary called attention to the NERC Antitrust Compliance Guidelines and the public meeting notice and directed questions to NERC's General Counsel, Charles Berardesco.

Introduction and Chair's Remarks
A. Gallo welcomed the Committee and guests and acknowledged the people attending as proxies.

Review March 20, 2019 Agenda (agenda item 1)
The Committee approved the March 20, 2019 meeting agenda by unanimous consent.

Consent Agenda (agenda item 2a)
The Committee approved the February 20, 2019 SC meeting minutes by unanimous consent.

Projects Under Development (agenda item 3)
H. Gugel reviewed the three month outlook, including an update on the Standards Efficiency Review. S. Bodkin asked a question about how the concepts will be prioritized, and H. Gugel clarified. C. Yeung reviewed the Project Tracking Spreadsheet. He highlighted relevant information for each project. H. Gugel reviewed the Projected Posting Schedule.

NERC Participant Conduct Policy (agenda item 4)
L. Perotti shared an overview of the new NERC Participant Conduct Policy. A. Gallo asked a clarifying question about media disclaimers. L. Oelker asked about how this will be shared with standard drafting teams.

2019 Standards Grading Process (agenda item 5)
H. Gugel provided background on the topic. S. Bodkin asked when the SC will reinitiate on the Standards Grading Process. H. Gugel clarified that the SC could pick this up in early 2020.

C. Yeung moved to endorse a delay of the Standards Grading process until May 2020, and inform the NERC Board of Trustees at its May 2019 meeting.

The Committee approved the motion with no objections or abstentions.

Standard Authorization Request Cyber System Information Access Management (agenda item 6)

S. Kim provided a background of the SAR, and that the CIP Committee endorsed the SAR.

F. McElvain moved to accept the Standards Authorization Request (SAR) submitted by Tri-State Generation and Transmission Association and authorize for a 30-day formal comment period; and authorize solicitation for nominees for a SAR drafting team for a 30-day nomination period.

The Committee approved the motion with no objections or abstentions.

Functional Model Advisory Group (agenda item 7)
A. Gallo shared background on the topic. The SC discussed the decision to form an ad hoc working group to evaluate potential next steps for the Functional Model (FM). G. Zito asked who will be included in the ad hoc group, the timeline for determining next steps. A. Gallo clarified that the group will be comprised of the leadership of the SC and Compliance and Certification Committee and NERC staff with participation by the other standing committees as needed. A. Gallo and H. Gugel shared that the group has not formulated a firm timeline, but all are interested in moving forward promptly. B. Lawson asked how the SC will handle the potential next steps. A. Gallo responded that the potential next steps will come before the SC for consideration and that any FM updates also require consensus by the technical committees.

F. McElvain moved to endorse informing the Functional Model Advisory Group (FMAG) to refrain from additional work pending the outcome of the ad hoc working group.

The Committee approved the motion with no objections or abstentions.

SC Charter Revisions (agenda item 8)
A. Gallo, on behalf of SCEC, shared background on the topic. D. Kiguel asked a question about Canadian representation. A. Gallo clarified that the Rules of Procedure covers the process and guidelines for Canadian representation. G. Zito asked about the use of the term results-based as compared to a risk-based.

G. Zito moved to approve revisions to the SC Charter for submission to the NERC Board of Trustees with the second sentence in Section 7.1 remaining unchanged: “The three segment members cannot represent the same industry segments the Committee officers previously represented, nor can any two of the segment members be from the same segment.”

The Committee approved the motion with no objections or abstentions.

Project 2015-09 System Operating Limits (agenda item 9)
S. Kim of NERC Staff shared a background on the topic. S. Solis, drafting team member, presented on the topic, which was included in the agenda package. The SC members ask questions of S. Solis and discussed the SDT recommendation, associated with FAC-011-4, to revise TOP-001-4 and IRO-008-2 to address issues related to logging and reporting System Operating Limit exceedances.

G. Zito moved to determine the modifications to IRO-008-2 and TOP-001-4 are within the scope of the existing SAR.

The Committee approved the motion with no objections or abstentions.

Project 2016-02 IROL Modifications (agenda item 10)
S. Kim shared background on the topic. The SC discussed the status of Project 2016-02 regarding modifications to CIP-002-5.1a and coordination with Project 2015-09. S. Bodkin raised a concern about replacing the term Interconnection Reliability Operating Limits (IROL) with the current IROL definition within CIP-002. H. Gugel provided more background on the matter.

Subcommittee Reports (agenda item 10)
C. Yeung updated on recent Project Management and Oversight Subcommittee (PMOS) activities with a focus on Project 2018-03 Standards Efficiency Review (SER) Retirements, and reactivating projects that have been placed on hold due to overlap with the SER project. S. Bodkin updated on recent Standards Committee Process Subcommittee (SCPS) activities, including improvement of the Standards Grading Tool.

Legal Update (agenda item 11)
L. Perotti provided the legal update regarding recent and upcoming filings.

New Business
None.

Adjournment
A. Gallo thanked the Committee members and observers and adjourned the meeting at 1:06 p.m. Central Time.

Attachment 1

Segment and Term	Representative	Organization	Proxy	Present (Member or Proxy)
Chair 2018-19	Andrew Gallo Director, Corporate Compliance	City of Austin dba Austin Energy		Yes
Vice Chair 2018-19	Amy Casuscelli Sr. Reliability Standards Analyst	Xcel Energy		Yes
Segment 1-2018-19	Vacant			N/A
Segment 1-2019-20	Sean Bodkin NERC Compliance Policy Manager	Dominion Resources Services, Inc.		Yes
Segment 2-2018-19	Michael Puscas Compliance Manager	ISO New England, Inc.		Yes
Segment 2-2019-20	Charles Yeung Executive Director Interregional	Southwest Power Pool		Yes
Segment 3-2018-19	Todd Bennett Manager Reliability Compliance	Associated Electric Cooperative, Inc.		Yes
Segment 3-2019-20	Linn Oelker Manager – Market Compliance	LG&E and KU Services Company		Yes
Segment 4-2018-19	Chris Gowder Regulatory Compliance Manager	Florida Municipal Power Agency		Yes
Segment 4-2019-20	Barry Lawson Associate Director, Power Delivery and Reliability	National Rural Electric Cooperative Association		Yes
Segment 5-2018-19	Yee Chou Director NERC Compliance Services	American Electric Power		Yes
Segment 5-2019-20	William Winters Chief Engineer, Electrical Engineering	Con Edison Company of New York, Inc.		Yes

Segment and Term	Representative	Organization	Proxy	Present (Member or Proxy)
Segment 6-2018-19	Jennifer Flandermeyer Director, Federal Regulatory Policy	Kansas City Power & Light Company (Great Plains Energy)	Douglas Webb	Yes
Segment 6-2019-20	Rebecca Moore Darrah Manager of Reliability Compliance	ACES Power		Yes
Segment 7-2018-19	Frank McElvain Senior Manager, Consulting	Siemens Power Technologies International		Yes
Segment 7-2019-20	Venona Greaff Senior Energy Analyst	Occidental Chemical Corporation		Yes
Segment 8-2018-19	Robert Blohm Managing Director	Keen Resources Ltd.		Yes
Segment 8-2019-20	David Kiguel	Independent		Yes
Segment 9-2018-19	Alexander Vedvik Senior Electrical Engineer	Public Service Commission of Wisconsin		Yes
Segment 9-2019-20	Michael Marchand Senior Policy Analyst	Arkansas Public Service Commission		Yes
Segment 10-2018-19	Guy Zito Assistant Vice President of	Northeast Power Coordinating Council		Yes
Segment 10-2019-20	Steve Rueckert Director of Standards	WECC		Yes

Agenda Item 4
Standards Committee
April 17, 2019

Project 2018-04 Modifications to PRC-024-2

Action

Authorize initial posting for a 45-day formal comment period, with ballot pool formed in the first 30 days and parallel initial ballot and non-binding polls during the last 10 days of the comment period for the following:

- Proposed Reliability Standard PRC-024-3; and
- The associated Implementation Plan and Violation Severity Levels and Violation Risk Factors.

Background

On November 27, 2018, the NERC Operating Committee (OC) and Planning Committee (PC) submitted a Standard Authorization Request (SAR) prepared by the Inverter-Based Resource Performance Task Force (IRPTF), which reports to the OC and PC. Based off disturbance analyses and development of the PRC-024-2 Gaps Whitepaper, the IRPTF identified potential modifications to PRC-024-2 to help ensure inverter-based generator owners, operators, developers, and equipment manufacturers understand the intent of the standard to require inverter-based generators to respond to grid disturbances in a manner contributing to the reliable operation of the Bulk Power System. The Project 2018-04 SAR was proposed to revise PRC-024-2 to address the identified issues.

From December 19, 2018 to January 18, 2019, NERC solicited nominations for a SAR drafting team (SAR DT) to revise Reliability Standard PRC-024-2. NERC submitted a list of recommended nominees to the Standards Committee (SC). On January 31, 2019, the SC appointed the SAR DT, which held a conference call on February 1, 2019 to review the comments and recommendations from an industry discussion and modified the SAR accordingly. The SC accepted the revised SAR and appointed the standard drafting team (SDT) on February 20, 2019. Throughout February and March 2019, the SDT conducted several conference calls and two in-person meetings to address the issues identified in the SAR.

The Quality Review (QR) for this posting was performed March 21 – 29, 2019. The SDT considered the QR inputs and revised the proposed standard where appropriate. The reviewed documents were presented to the full SDT for consideration, and the SDT approved the final documents for submission to the SC for authorization to post for a 45-day comment period with initial ballot. There were no deviations from the Standard Processes Manual.

QR participants included:

- NERC staff – Marisa Hecht, Al McMeekin, Rich Bauer, Ryan Mauldin, Wendy Muller, and Mat Bunch
- SDT Leadership – Bryan Burch (Southern Company) and Jeff Billo (ERCOT)
- SC Member – Sean Bodkin (Dominion Resources, Inc.)
- SDT Observer – Jason Espinosa (Seminole Electric Cooperative, Inc.)

- SDT Observer – Maysam Radvar (Ready Technologies)
- Majid Fassi Fehri (Hydro Quebec)

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

PRC-024-3 is posted for a 45-day formal comment period with initial ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	December 2018
SAR posted for comment	December 19, 2018–January 19, 2019
Standards Committee accepted the revised SAR	February 20, 2019

Anticipated Actions	Date
45-day formal comment period with ballot	April – June 2019
45-day formal or informal comment period with additional ballot	July – August 2019
10-day final ballot	October 2019
Board adoption	November 2019

A. Introduction

1. **Title:** Generator Frequency and Voltage Protection Settings

2. **Number:** PRC-024-3

3. **Purpose:** To set generator protection, such that generating resource(s) remain connected, continuing to support the BES during defined frequency and voltage excursions.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owners that apply protection listed in Section 4.2.1.

   4.1.2. Transmission Owners that own a BES generator step-up (GSU) transformer or collector transformer and apply protection listed in Section 4.2.1.

   4.2. Facilities:

   4.2.1 Frequency, voltage or volts per hertz protection, including frequency or voltage protective functions within control systems that provide tripping or momentary cessation signals to all or part of the generating resource, applied to the following:

   4.2.1.1 Bulk Electric System (BES) generating resource(s).

   4.2.1.2 BES GSU transformer(s).

   4.2.1.3 High side of the generator-connected unit auxiliary transformer installed on BES generating resource(s).

   4.2.1.4 Individual dispersed power producing resources identified in the BES Definition, Inclusion I4.

   4.2.1.5 Elements utilized in aggregation of the dispersed power producing resources.

   4.2.1.6 Collector transformer of resources identified in the BES Definition, Inclusion I4.

5. **Effective Date:** See Implementation Plan for PRC-024-3

B. Requirements and Measures

R1. Each Generator Owner or Transmission Owner shall set its applicable frequency protection such that the generating resource does not trip or enter momentary cessation within the "no trip zone" of PRC-024 Attachment 1, subject to the following exception: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating resource(s) may be set to trip or enter momentary cessation within the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M1. Each Generator Owner or Transmission Owner shall have evidence that the applicable frequency protection has been set in accordance with Requirement R1, such as dated setting sheets, calibration sheets, calculations, or other documentation.

R2. Each Generator Owner or Transmission Owner shall set its applicable voltage protection such that the generating resource does not trip or enter momentary cessation within the "no trip zone" of PRC-024 Attachment 2 during a voltage excursion at the high side of the GSU or collector transformer, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- If the Transmission Planner allows less stringent voltage protection settings than those required to meet PRC-024 Attachment 2, then the Generator Owner or Transmission Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.
- Generating resource(s) may trip or enter momentary cessation within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M2. Each Generator Owner or Transmission Owner shall have evidence that applicable voltage protection has been set in accordance with Requirement R2, such as dated setting sheets, voltage-time boundaries, calibration sheets, coordination plots, dynamic simulation studies, calculations, or other documentation.

R3. Each Generator Owner or Transmission Owner shall document each known regulatory or equipment limitation[1] that prevents an applicable generating resource(s) with generator frequency or voltage protection from meeting the protection setting criteria in Requirements R1 or R2, including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner or Transmission Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously

[1] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protection itself but does not exclude limitations originating in the equipment that it protects.

documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

M3. Each Generator Owner or Transmission Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3, such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

R4. Each Generator Owner or Transmission Owner shall provide its applicable generator protection settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated generating resource(s) within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of protection setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Generator Owner or Transmission Owner shall have evidence that it communicated applicable generator protection settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority:** "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

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

   The applicable 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.

   - The Generator Owner or Transmission Owner shall keep data or evidence of Requirements R1 through R4 for 3 years or until the next audit, whichever is longer.
   - If a Generator Owner or Transmission Owner is found non-compliant, the Generator Owner or Transmission Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

   1.3. **Compliance Monitoring and Enforcement Program:** As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to set its applicable frequency protection so that it does not trip or enter momentary cessation according to Requirement R1.
R2.	N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to set its applicable voltage protection so that it does not trip or enter momentary cessation according to Requirement R2.
R3.	The Generator Owner or Transmission Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days	The Generator Owner or Transmission Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days	The Generator Owner or Transmission Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days	The Generator Owner or Transmission Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2. OR The Generator Owner or Transmission Owner failed to communicate the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	but less than or equal to 60 calendar days of identifying the limitation.	but less than or equal to 90 calendar days of identifying the limitation.	but less than or equal to 120 calendar days of identifying the limitation.	documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4.	The Generator Owner or Transmission Owner provided its generator protection settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided generator protection settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner or Transmission Owner provided its generator protection settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided generator protection settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner or Transmission Owner provided its generator protection settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided generator protection settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner or Transmission Owner failed to provide its generator protection settings within 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner failed to provide generator protection settings within 150 calendar days of a written request.

D. Regional Variances

D.A. Variance for the Quebec Interconnection

This Interconnection-wide Variance shall be applicable in the Quebec Interconnection and replaces, in its entirety, continent-wide Requirement R2 with the following:

D.A.2. Each Generator Owner or Transmission Owner shall set its applicable voltage protection such that the generating resource does not trip or enter momentary cessation within the “no trip zone” of PRC-024 Attachment 2a during a voltage excursion at the high side of the GSU or collector transformer, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- If the Transmission Planner allows less stringent voltage protection settings than those required to meet PRC-024 Attachment 2a, then the Generator Owner or Transmission Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner’s study.
- Generating resource(s) may trip or enter momentary cessation within a portion of the “no trip zone” of PRC-024 Attachment 2a for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- Inverter-based resources voltage protection settings may be set to enter momentary cessation within the “no trip zone” of PRC-024 Attachment 2a during a voltage excursion at the high side of the MPT under the following conditions:
  - After a minimum delay of 0.022 s, when the positive-sequence voltage exceeds 1.25 per unit (p.u.) Normal operation must resume once the voltage drops back below 1.25 p.u.
  - After a minimum delay of 0.022 s, when the phase-to-ground root mean square (RMS) voltages exceeds 1.4 p.u., as measured at generator terminals, on one or multiple phases. Normal operation must resume once the voltage drops back below the 1.25 p.u.

M.D.A.2. Each Generator Owner or Transmission Owner shall have evidence that applicable voltage protection has been set in accordance with Requirement R2, such as dated setting sheets, voltage-time boundaries, calibration sheets, coordination plots, dynamic simulation studies, calculations, or other documentation.

E. Associated Documents

Implementation Plan

Industry Recommendation I – Loss of Solar Resources during Transmission Disturbances Due to Inverter Settings

Industry Recommendation II – Loss of Solar Resources during Transmission Disturbances due to Inverter Settings

Blue Cut Fire Disturbance

Canyon 2 Fire Disturbance

"Protective Relaying For Power Generation Systems", Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

"IEEE C37.102 IEEE Guide for AC Generator Protection"

"IEEE C50.13 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above"

"IEEE C37.106 IEEE Guide for Abnormal Frequency Protection for Power Generating Plants"

Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	
1	March 20, 2014	FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)	
2	February 12, 2015	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 29, 2015	FERC Letter Order in Docket No. RD15-3-000 approving PRC-024-2	Modifications to adjust the applicability to owners of dispersed generation resources.

Attachment 1
(Frequency No Trip Boundary by Interconnection)

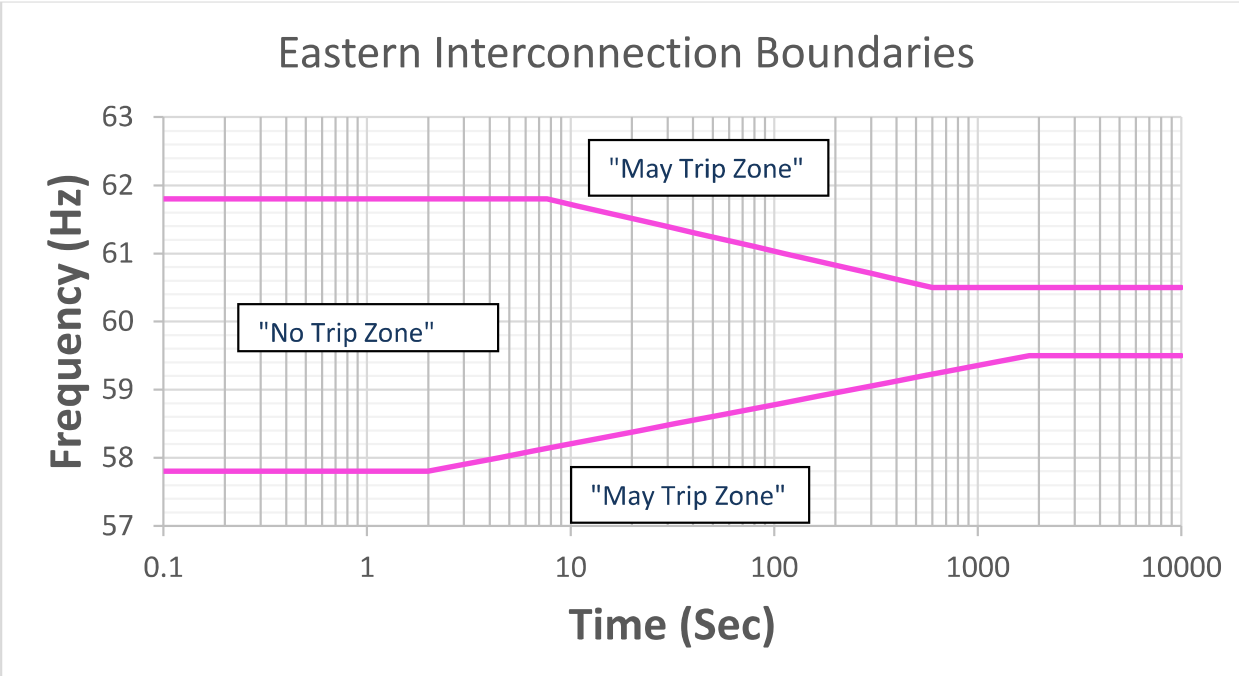

Figure 1

Frequency Boundary Data Points – Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (sec)
≥61.8	0.10	≤57.8	0.10
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Table 1

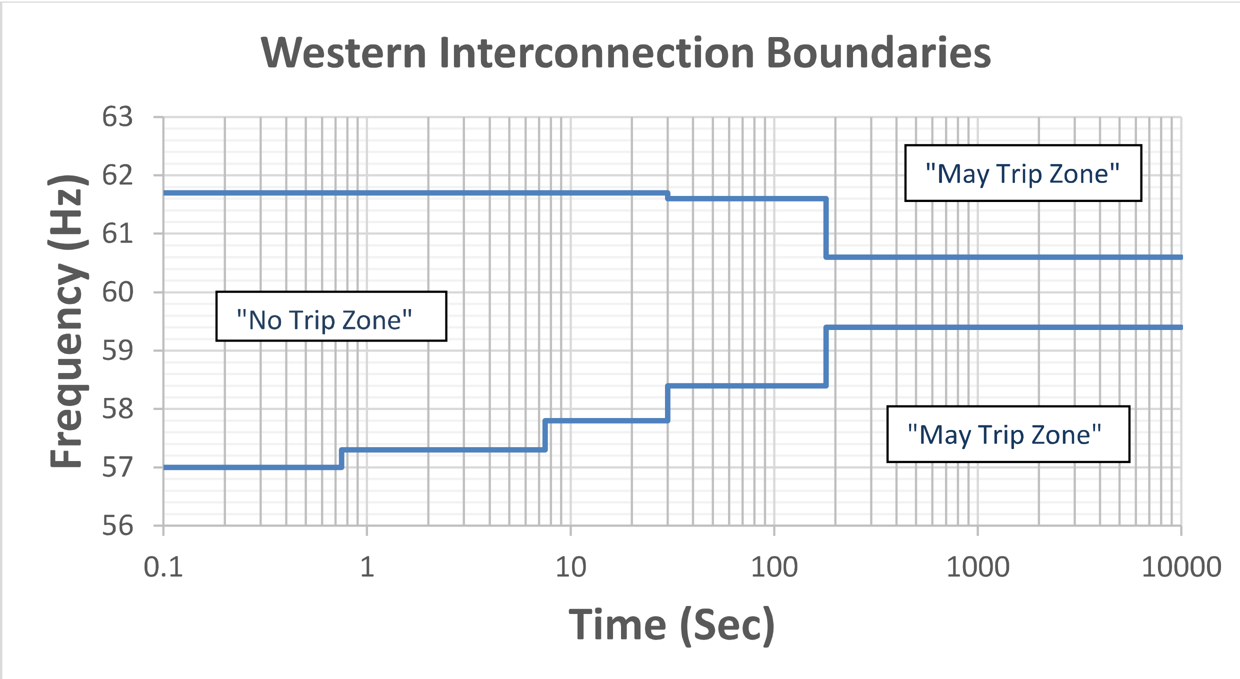

Figure 2

Frequency Boundary Data Points – Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Minimum Time (Sec)**	**Frequency (Hz)**	**Minimum Time (sec)**
≥61.7	0.10	≤57.0	0.10
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

Table 3

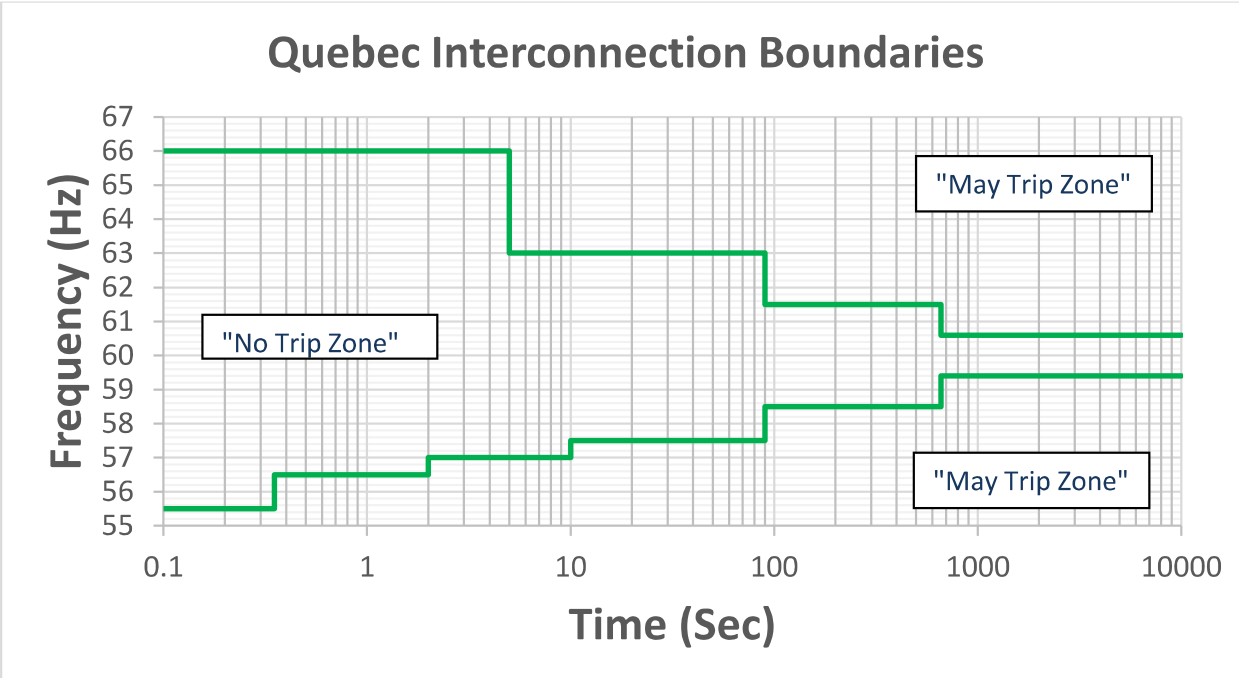

Figure 4

Frequency Boundary Data Points – Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Minimum Time (Sec)**	**Frequency (Hz)**	**Minimum Time (Sec)**
>66.0	0.10	<55.5	0.10
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

Table 2

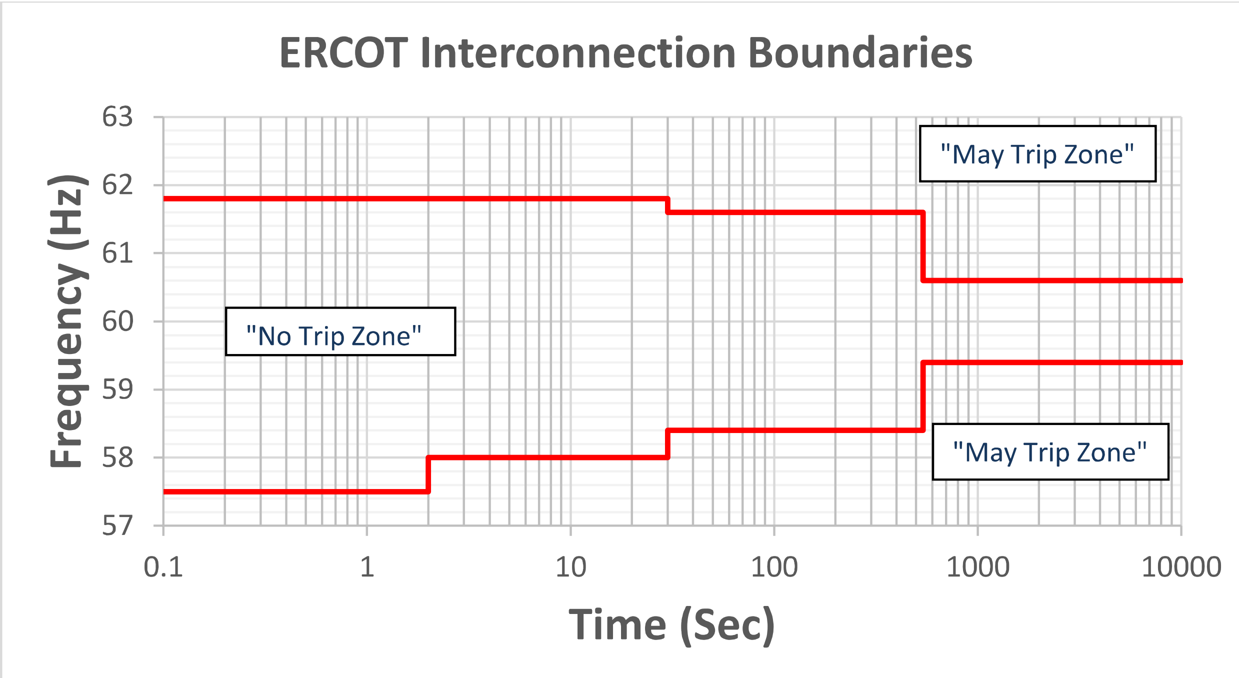

Figure 5

Frequency Boundary Data Points – ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (sec)
≥61.8	0.10	≤57.5	0.10
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

Table 3

PRC-024— Attachment 2

(Voltage No-Trip Boundary – Eastern, Western, and ERCOT Interconnections)

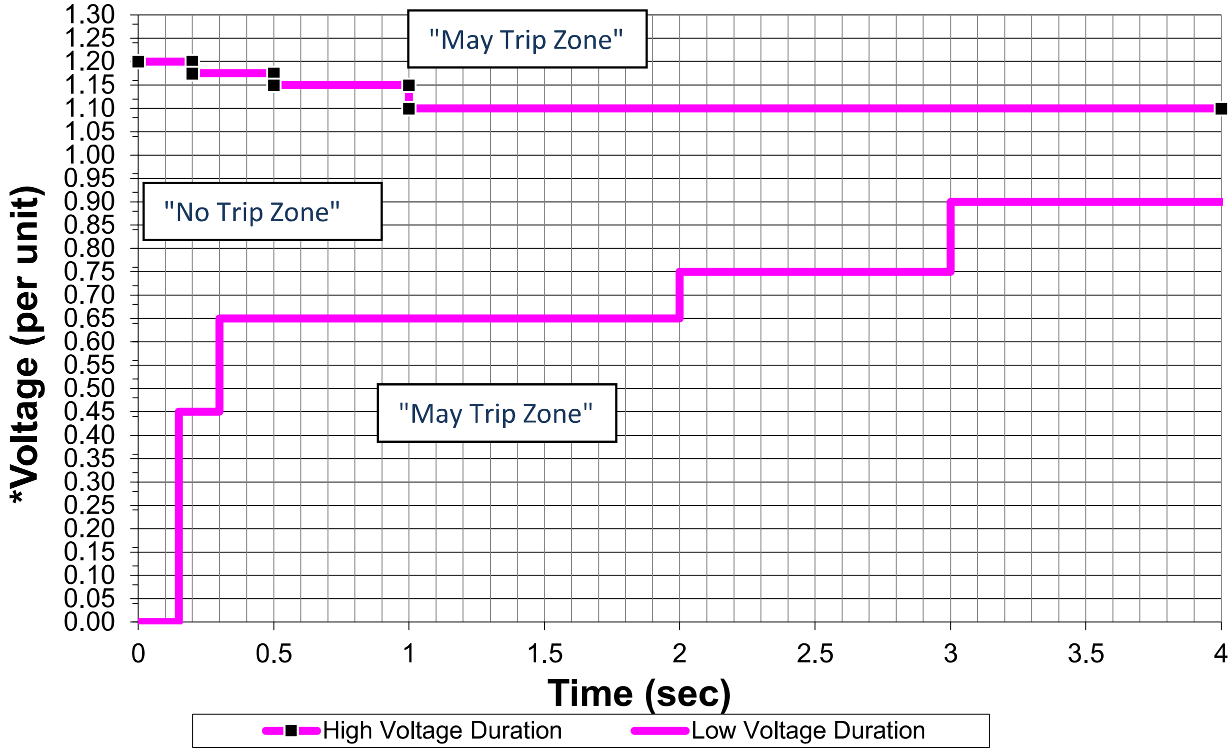

Figure 1

Voltage Boundary Data Points

High Voltage Duration		Low Voltage Duration	
Voltage (pu)	Minimum Time (sec)	Voltage (pu)	Minimum Time (sec)
≥1.200	0.00	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00
<1.10	4.00	≥ 0.90	4.00

Table 1

* Voltage at the high-side of the GSU or collector transformer.

Voltage Boundary Clarifications – Eastern, Western, and ERCOT Interconnections

Boundary Details:

1. The per unit voltage base for these boundaries is the nominal operating voltage (e.g., 115 kV, 138 kV, 230 kV, 345 kV, 500 kV, etc.).
2. The boundaries apply to voltage excursions regardless of the type of initiating event.
3. The values in the table represent the minimum time durations allowed for specified voltage excursion thresholds.
4. The boundaries assume a system frequency of 60 Hertz. When evaluating volts per hertz protection, magnitude of the high voltage boundary can be adjusted in proportion to deviations of frequency below 60 Hertz.
5. Voltages in the boundaries assume RMS fundamental frequency phase-to-ground or phase-to-phase voltage.
6. The “no trip zone” ends at 4 seconds.

Evaluating Protection Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating.
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
    d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection settings accounting for the actual tap settings of transformers between the generator terminals and the high side of the GSU or collector transformer.

PRC-024— Attachment 2a

(Voltage No Trip Boundaries – Quebec Interconnection)

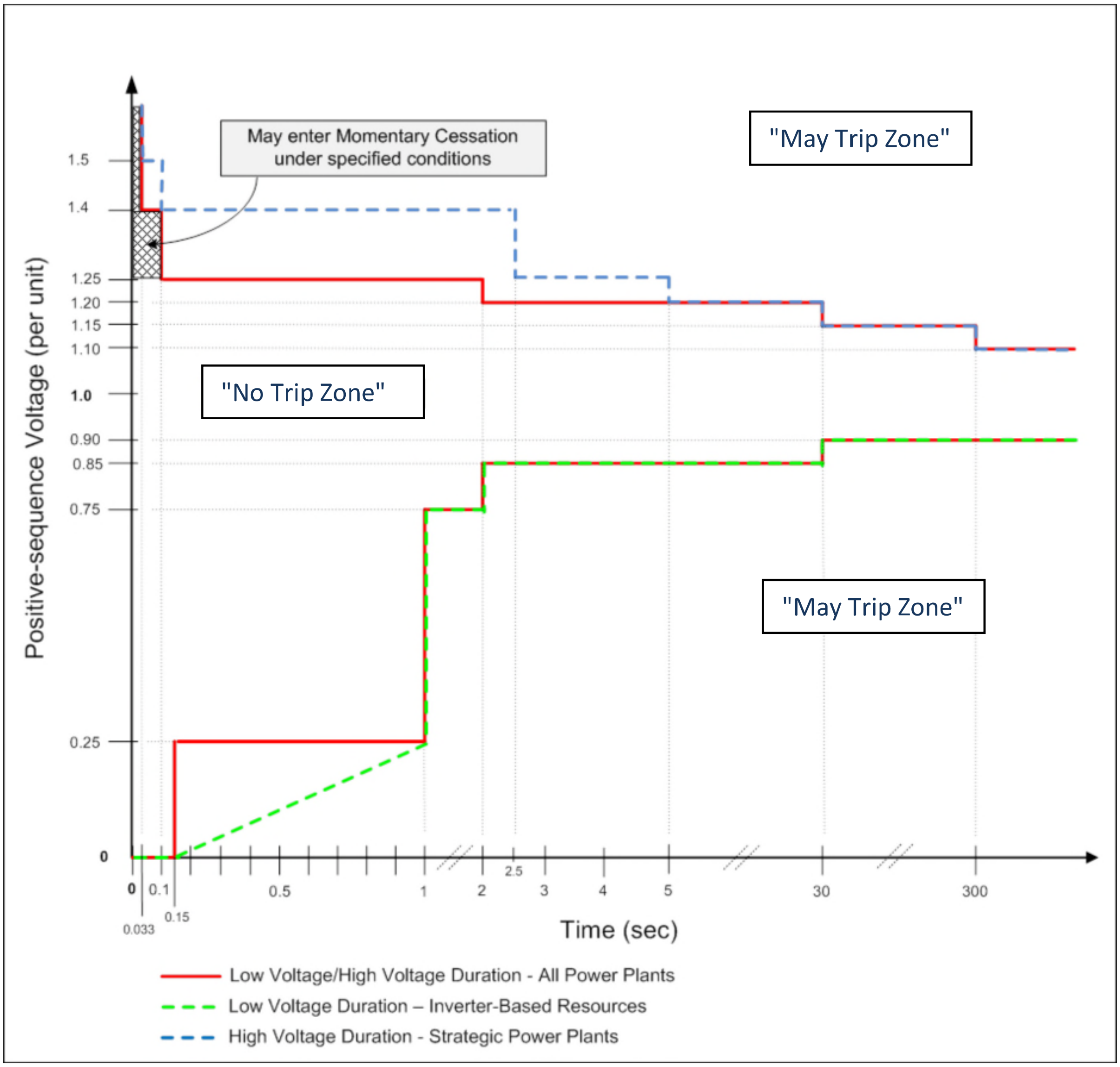

Figure 1

Voltage Boundary Data Points – Quebec Interconnection

High Voltage Duration for all Power Plants		High Voltage Duration for strategic[1] Power Plants	
Voltage (pu)	Minimum Time (sec)	Voltage (pu)	Minimum Time (sec)
---	---	>1.50	0.033
>1.40	0.033	>1.40	0.10
>1.25	0.10	>1.25	2.50
>1.20	2.00	>1.20	5.00
>1.15	30	>1.15	30
>1.10	300	>1.10	300
≤1.10	continuous	≤1.10	continuous

Table 1

Voltage Boundary Data Points – Quebec Interconnection

Low Voltage Duration for all Power Plants		Low Voltage Duration for Inverter-Based Resources	
Voltage (pu)	Minimum Time (sec)	Voltage (pu)	Minimum Time (sec)
<0.25	0.15	<0.25	3.4*V(pu)+0.15
<0.75	1.00	<0.75	1.00
<0.85	2.00	<0.85	2.00
<0.90	30	<0.90	30
≥0.90	continuous	≥0.90	continuous

Table 2

[1] Power Plants designated by the Transmission Planner for protecting the integrity of Transmission System equipment.

Voltage Boundary Clarifications – Quebec Interconnection

Boundary Details:

1. The per unit voltage base for these boundaries is the nominal operating voltage (e.g., 115 kV, 138 kV, 230 kV, 345 kV, 500 kV, etc.).
2. The boundaries apply to voltage excursions regardless of the type of initiating event.
3. The values in the table represent the minimum time durations allowed for specified voltage excursion thresholds.
4. The boundaries assume a system frequency of 60 Hertz. When evaluating volts per hertz protection, magnitude of the high voltage boundary can be adjusted in proportion to deviations of frequency below 60 Hertz.
5. Voltages in the boundaries assume positive-sequence values.

Evaluating Protection Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating.
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
    d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection settings accounting for the actual tap settings of transformers between the generator terminals and the high side of the GSU or collector transformer.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

PRC-024-3 is posted for a 45-day formal comment period with initial ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	December 2018
SAR posted for comment	December 19, 2018 – January 19, 2019
Standards Committee accepted the revised SAR	February 20, 2019

Anticipated Actions	Date
45-day formal or informal comment period with ballot	April – June 2019
45-day formal or informal comment period with additional ballot	July – August 2019
10-day final ballot	October 2019
Board adoption	November 2019

A. Introduction

1. **Title:** Generator Frequency and Voltage Protection ~~Protective Relay~~ Settings
2. **Number:** PRC-024-3~~PRC-024-2~~
3. **Purpose:** ~~Ensure Generator Owners~~ To set ~~their~~ generator protection, ~~protective relays~~ such that generating resource(s) ~~units~~ remain connected, continuing to support the BES during defined frequency and voltage excursions.
4. **Applicability:**

   4.1. ~~Generator Owner~~Functional Entities:

   4.1.1. Generator Owners that apply protection listed in Section 4.2.1.

   4.1.2. Transmission Owners that own a BES generator step-up (GSU) transformer or collector transformer and apply protection listed in Section 4.2.1.

   4.2. Facilities:

   4.2.1 Frequency, voltage or volts per hertz protection, including frequency or voltage protective functions within control systems that provide tripping or momentary cessation signals to all or part of the generating resource, applied to the following:

   4.2.1.1 Bulk Electric System (BES) generating resource(s).

   4.2.1.2 BES GSU transformer(s).

   4.2.1.3 High side of the generator-connected unit auxiliary transformer installed on BES generating resource(s).

   4.2.1.4 Individual dispersed power producing resources identified in the BES Definition, Inclusion I4.

   4.2.1.5 Elements utilized in aggregation of the dispersed power producing resources.

   4.2.1.6 Collector transformer of resources identified in the BES Definition, Inclusion I4.

5. **Effective Date:** See Implementation Plan for ~~PRC-024-2~~ PRC-024-3

B. Requirements and Measures

R1. Each Generator Owner or Transmission Owner ~~that has generator frequency protective relaying[1] activated to trip its applicable generating unit(s)~~ shall set its applicable frequency protection ~~protective relaying~~ such that the ~~the generator frequency protective relaying~~generating resource does not trip or enter momentary cessation ~~the applicable generating unit(s)~~ within the "no trip zone" of PRC-024 Attachment 1, subject to the following exception~~s~~[2]: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- ~~Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.~~
- ~~Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).~~
- Generating resource(s) ~~unit(s)~~ may be set to trip or enter momentary cessation within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M1. Each Generator Owner or Transmission Owner shall have evidence that the applicable frequency protection has ~~generator frequency protective relays have~~ been set in accordance with Requirement R1, such as dated setting sheets, calibration sheets, calculations, or other documentation.

R2. Each Generator Owner or Transmission Owner ~~that has generator voltage protective relaying[1] activated to trip its applicable generating unit(s)~~ shall set its ~~protective relaying~~applicable voltage protection such that the ~~generator voltage protective relaying~~generating resource does not trip or enter momentary cessation within the "no trip zone" of PRC-024 Attachment 2~~the applicable generating unit(s) as a result of a~~ during a- voltage excursion at the high side of the GSU or collector transformer, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* ~~(at the point of interconnection[3]) caused by an event on the~~

~~[1] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.~~

~~[2] For frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual generating unit of the dispersed power producing resources, as well as frequency protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.~~

~~transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2.~~[4]

- If the Transmission Planner allows less stringent voltage ~~relay~~ protection settings than those required to meet PRC-024 Attachment 2, then the Generator Owner or Transmission Owner may ~~shall~~ set its protection ~~protective relaying~~ within the voltage recovery characteristics of a location-specific Transmission Planner's study. ~~Requirement R2 is subject to the following exceptions: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]~~
- ~~Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).~~
- ~~Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).~~
- ~~Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.~~
- Generating resource(s) ~~unit(s)~~ may trip or enter momentary cessation within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M2. Each Generator Owner or Transmission Owner shall have evidence that applicable ~~generator~~ voltage protection has~~protective relays have~~ been set in accordance with Requirement R2, such as dated setting sheets, voltage-time boundaries, calibration sheets, coordination plots, dynamic simulation studies, calculations, ~~-~~ or other documentation.

R3. Each Generator Owner or Transmission Owner shall document each known regulatory or equipment limitation[5] that prevents an applicable generating resource(s)~~unit~~ with generator frequency or voltage ~~protective relays~~protection from meeting the ~~relay~~ protection setting criteria in Requirements R1 or R2, including (but not limited to)

~~[3] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.~~

~~[4] For voltage protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to voltage protective relays applied on the individual generating unit of the dispersed power producing resources, as well as voltage protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.~~

[5] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protection ~~protective relays themselves~~ itself but does not exclude limitations originating in the equipment that ~~they~~ it protects.

study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner or Transmission Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

M3. Each Generator Owner or Transmission Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations ~~(excluding limitations noted in footnote 3)~~ that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3, such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

R4. Each Generator Owner or Transmission Owner shall provide its applicable generator protection ~~trip~~ settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated generating resource(s) ~~unit~~ within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested ~~trip~~ settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of ~~relay~~ protection setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Generator Owner or Transmission Owner shall have evidence that it communicated applicable generator ~~protective relay trip~~ protection settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

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

The applicable 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.

- The Generator Owner or Transmission Owner shall keep data or evidence of Requirements R1 through R4 for 3 years or until the next audit, whichever is longer.
- If a Generator Owner or Transmission Owner is found non-compliant, the Generator Owner or Transmission Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Generator Owner or Transmission Owner ~~that has frequency protection activated to trip a generating unit,~~ failed to set its applicable ~~generator~~ frequency protection ~~protective relaying~~ so that it does not trip or enter momentary cessation ~~within the criteria listed in~~according to Requirement R1. ~~unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.~~
R2.	N/A	N/A	N/A	The Generator Owner or Transmission Owner ~~with voltage protective relaying activated to trip a generating unit,~~ failed to set its applicable voltage protection ~~protective relaying~~ so that it does not trip or enter momentary cessation ~~as a result of a voltage excursion~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~at the point of interconnection, caused by an event external to the plant per the criteria specified in~~according to Requirement R2. ~~unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.~~
R3.	The Generator Owner or Transmission Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	The Generator Owner or Transmission Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	The Generator Owner or Transmission Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	The Generator Owner or Transmission Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2. OR The Generator Owner or Transmission Owner failed to communicate the documented limitation to its Planning Coordinator and

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Transmission Planner within 120 calendar days of identifying the limitation.
R4.	The Generator Owner or Transmission Owner provided its generator protection settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided generator protection settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner or Transmission Owner provided its generator protection settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided generator protection settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner or Transmission Owner provided its generator protection settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided generator protection settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection settings within 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner Transmission Owner failed to provide generator protection settings within 150 calendar days of a written request.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL

D. Regional Variances

D.A. Variance for the Quebec Interconnection

This Interconnection-wide Variance shall be applicable in the Quebec Interconnection and replaces~~-~~, in its entirety, continent-wide Requirement R2 with the following:

D.A.2. Each Generator Owner or Transmission Owner shall set its applicable voltage protection such that the generating resource does not trip or enter momentary cessation within the "no trip zone" of PRC-024 Attachment 2a during a voltage excursion at the high side of the GSU or collector transformer, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- If the Transmission Planner allows less stringent voltage protection settings than those required to meet PRC-024 Attachment 2a, then the Generator Owner or Transmission Owner may set its protection- within the voltage recovery characteristics of a location-specific Transmission Planner's study.
- Generating resource(s) may trip or enter momentary cessation within a portion of the "no trip zone" of PRC-024 Attachment 2a for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- Inverter-based resources voltage protection settings may be set to enter momentary cessation within the "no trip zone" of PRC-024 Attachment 2a during a voltage excursion at the high side of the MPT under the following conditions:
    - After a minimum delay of 0.022 s, when the positive-sequence voltage exceeds 1.25 per unit (p.u.) Normal operation must resume once the voltage drops back below 1.25 p.u.
    - After a minimum delay of 0.022 s, when the phase-to-ground RMS voltages exceeds 1.4p.u., as measured at generator terminals, on one or multiple phases. Normal operation must resume once the voltage drops back below the 1.25 p.u.

M.D.A.2. Each Generator Owner or Transmission Owner shall have evidence that applicable voltage protection has been set in accordance with Requirement R2 such as dated setting sheets, voltage-time boundaries, calibration sheets, coordination plots, dynamic simulation studies, calculations, or other documentation.

~~D.~~E. Associated Documents

Implementation Plan

Industry Recommendation I – Loss of Solar Resources during Transmission Disturbances Due to Inverter Settings

Industry Recommendation II – Loss of Solar Resources during Transmission Disturbances due to Inverter Settings

Blue Cut Fire Disturbance

Canyon 2 Fire Disturbance

Field Code Changed

"Protective Relaying For Power Generation Systems", Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

"IEEE C37.102 IEEE Guide for AC Generator Protection"

"IEEE C50.13 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above"

"IEEE C37.106 IEEE Guide for Abnormal Frequency Protection for Power Generating Plants"

Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	
1	March 20, 2014	FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)	
2	February 12, 2015	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 29, 2015	FERC Letter Order in Docket No. RD15-3-000 approving PRC-024-2	Modifications to adjust the applicability to owners of dispersed generation resources.

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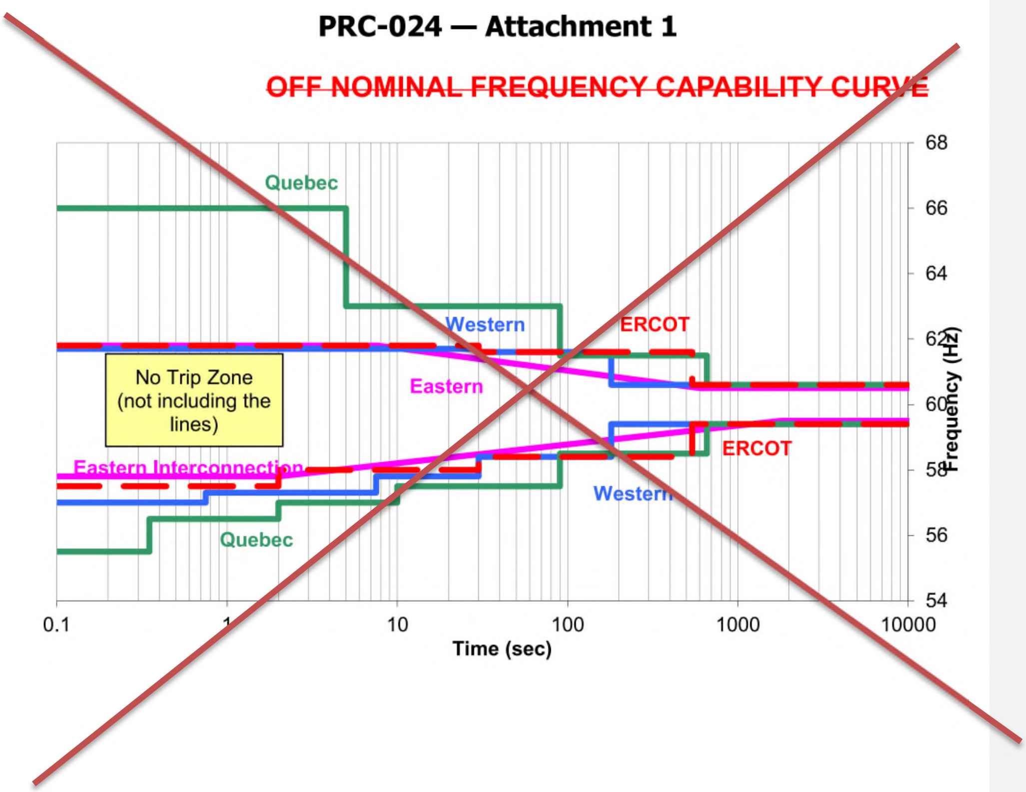
PRC-024 — Attachment 1
~~OFF NOMINAL FREQUENCY CAPABILITY CURVE~~
Quebec
Western
ERCOT
Eastern
No Trip Zone (not including the lines)
Eastern Interconnection
ERCOT
Western
Quebec
68
66
64
62
60
58
56
54
Frequency (Hz)
0.1
1
10
100
1000
10000
Time (sec)

Attachment 1

~~OFF NOMINAL FREQUENCY CAPABILITY CURVE~~

(Frequency No Trip Boundary by Interconnection)

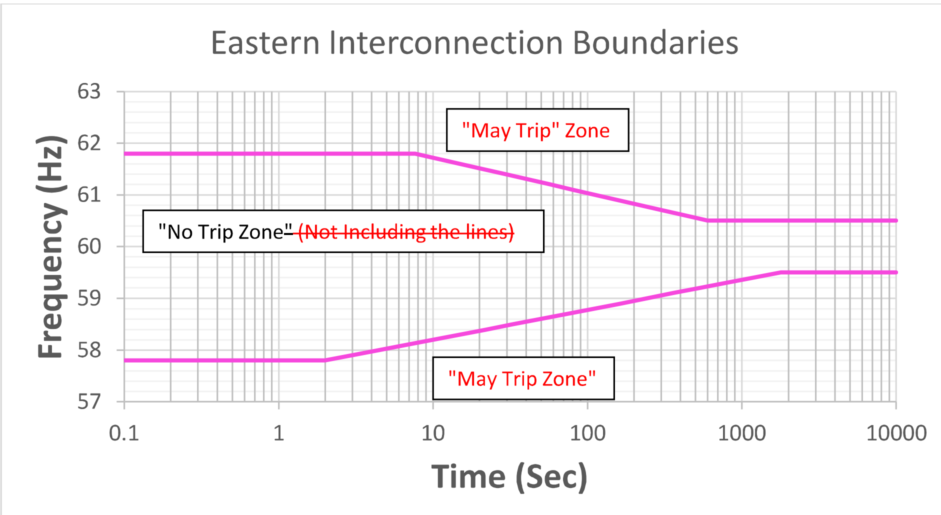

Figure 1

~~Curve~~ Frequency Boundary Data Points – Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (sec)
≥61.8	0.10~~Instantaneous trip~~	≤57.8	0.10~~Instantaneous trip~~
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Table 1

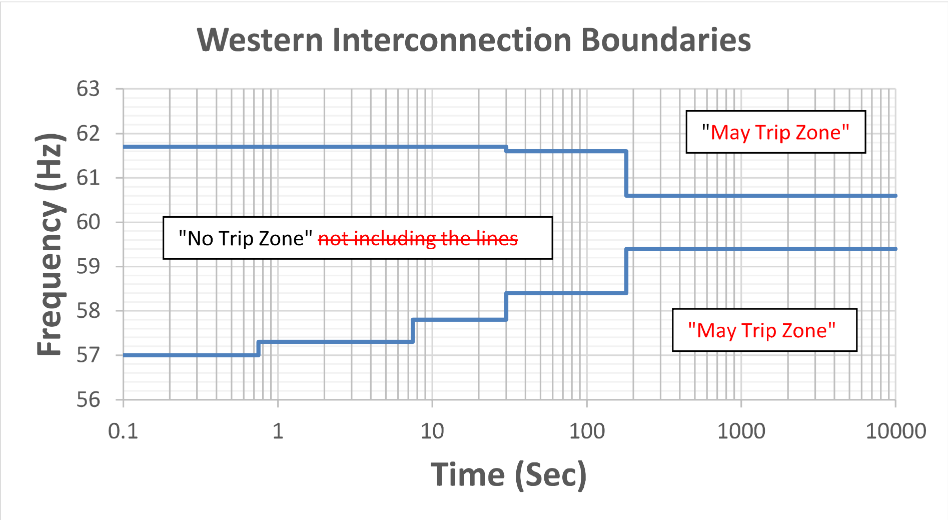

Figure 2

~~Curve~~Frequency- Boundary Data Points – Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (sec)
≥61.7	0.10~~Instantaneous trip~~	≤57.0	0.10~~Instantaneous trip~~
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

Table 3

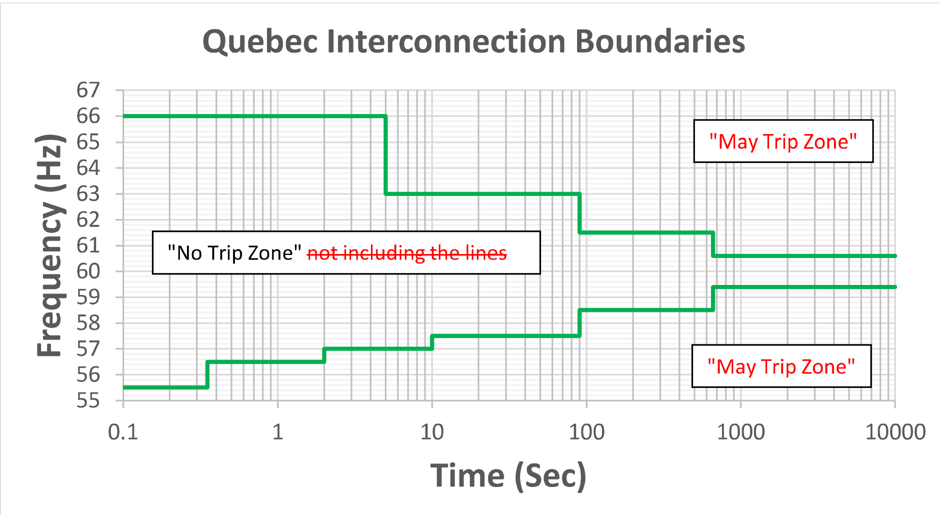

Figure 4

~~Curve~~ Frequency Boundary Data Points – Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (Sec)
>66.0	0.10~~Instantaneous trip~~	<55.5	0.10~~Instantaneous trip~~
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

Table 2

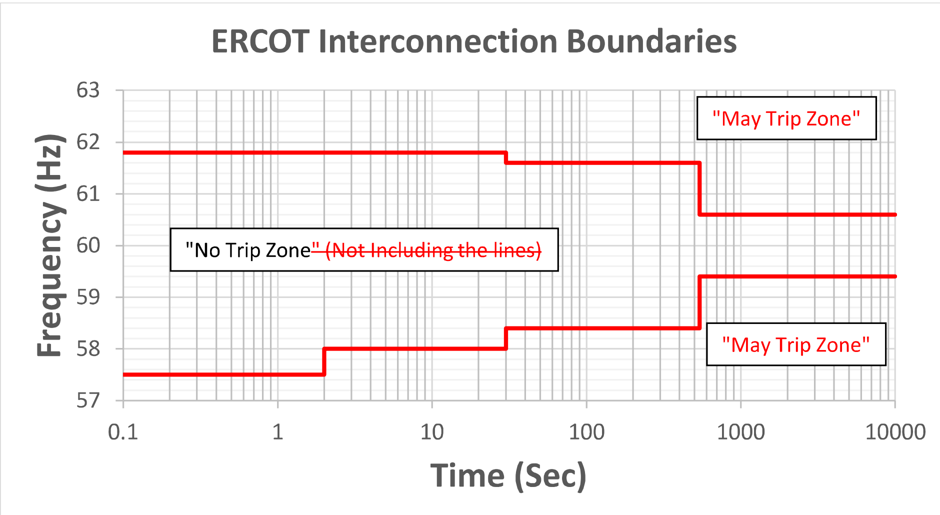

Figure 5

~~Curve~~ Frequency ~~-~~Boundary Data Points – ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Minimum Time (Sec)**	**Frequency (Hz)**	**Minimum Time (sec)**
≥61.8	0.10~~Instantaneous trip~~	≤57.5	0.10~~Instantaneous trip~~
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

Table 3

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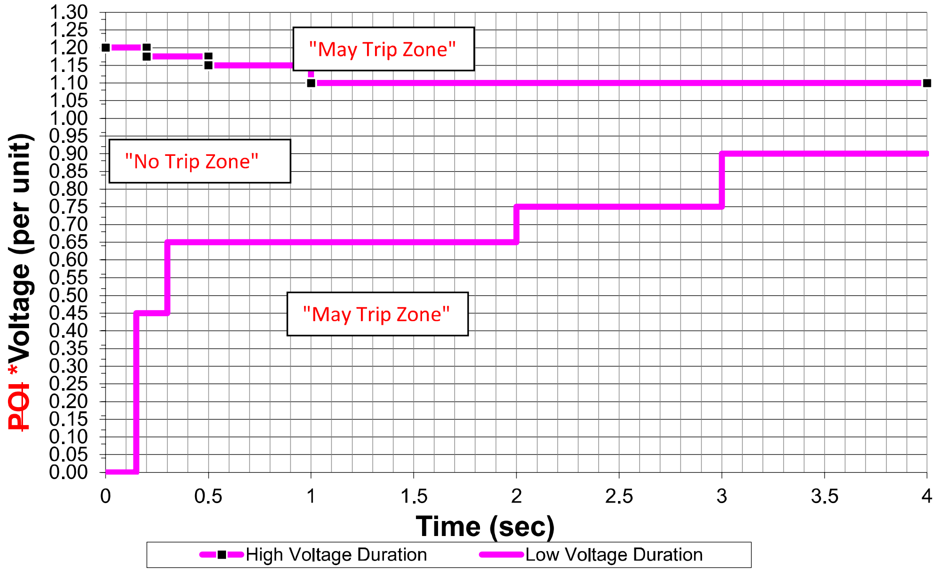
PRC-024— Attachment 2

(Voltage No-Trip Boundary – Eastern, Western, and ERCOT Interconnections)



6

Figure 1

Voltage Boundary Data Points ~~Ride Through Duration:~~

High Voltage ~~Ride Through~~ Duration		Low Voltage ~~Ride Through~~ Duration	
Voltage (pu)	Minimum Time (sec)	Voltage (pu)	Minimum Time (sec)
≥1.200	~~Instantaneous trip~~0.00	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

*Voltage at the high-side of the GSU or collector transformer.

<1.10	4.00	≥ 0.90	4.00

Table 1

Voltage at the high-side of the GSU or collector transformer.

Voltage Boundary Clarifications – Eastern, Western, and ERCOT Interconnections

Boundary Details:

1. The per unit voltage base for these boundaries~~curves~~ is the nominal operating voltage (e.g., 115 kV, 138 kV, 230 kV, 345 kV, 500 kV, etc.). ~~specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).~~
2. ~~The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles.~~ The boundaries apply to voltage excursions regardless of the type of initiating event.
3. The values in the table represent the minimum time durations allowed for specified voltage excursion thresholds.~~envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.~~
4. The boundaries ~~curves depicted~~ assume a system frequency ~~is~~ of 60 Hertz.~~–~~ When evaluating volts per hertz~~Volts/Hertz~~ protection, ~~you may adjust the~~ magnitude of the high voltage ~~curve~~ boundary can be adjusted in proportion to deviations of frequency below 60 Hertz.
5. Voltages in the ~~curve~~ boundaries assume RMS ~~minimum~~ fundamental frequency phase-to-ground or phase-to-phase voltage. ~~for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve~~

~~5.~~6. The “no trip zone” ends at 4 seconds.

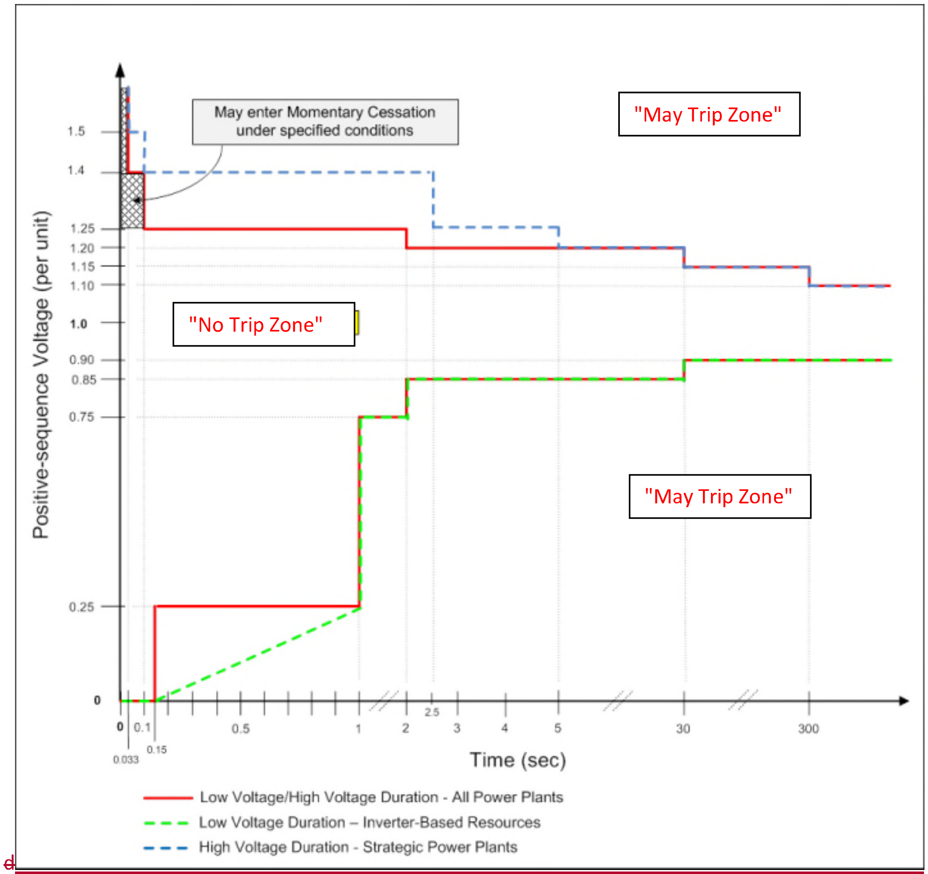
Evaluating Protection~~Protective~~ ~~Relay~~ Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection ~~relay~~ setting calculations on the static case for steady state initial conditions:
   a. All of the units connected to the same transformer are online and operating.
   b. All of the units are at full nameplate real-power output.
   c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
   d. The automatic voltage regulator is in automatic voltage control mode.

~~2.~~ Evaluate voltage protection ~~relay~~ settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.

~~3.~~ Evaluate voltage protection ~~relay~~ settings accounting for the actual tap settings of transformers between the generator terminals and the ~~point of interconnection~~ high side of the GSU or collection transformer.

PRC-024— Attachment 2a
(Voltage No Trip Boundaries – Quebec Interconnection)



~~d~~
Figure 1a

Voltage Boundary Data Points – Quebec Interconnection

High Voltage Duration for all Power Plants		High Voltage Duration for strategic[1] Power Plants	
Voltage (pu)	**Minimum Time (sec)**	**Voltage (pu)**	**Minimum Time (sec)**
---	---	>1.50	0.033
>1.40	0.033	>1.40	0.10
>1.25	0.10	>1.25	2.50
>1.20	2.00	>1.20	5.00
>1.15	30	>1.15	30
>1.10	300	>1.10	300
≤1.10	continuous	≤1.10	continuous

Table 1a

Voltage Boundary Data Points – Quebec Interconnection

Low Voltage Duration for all Power Plants		Low Voltage Duration for Inverter-Based Resources	
Voltage (pu)	**Minimum Time (sec)**	**Voltage (pu)**	**Minimum Time (sec)**
<0.25	0.15	<0.25	3.4*V(pu)+0.15
<0.75	1.00	<0.75	1.00
<0.85	2.00	<0.85	2.00
<0.90	30	<0.90	30
≥0.90	continuous	≥0.90	continuous

Table 2a

[1] Power Plants designated by the Transmission Planner for protecting the integrity of Transmission System equipment.

Voltage Boundary Clarifications – Quebec Interconnection

Boundary Details:

1. The per unit voltage base for these boundaries is the nominal operating voltage (e.g., 115 kV, 138 kV, 230 kV, 345 kV, 500 kV, etc.).
2. The boundaries apply to voltage excursions regardless of the type of initiating event.
3. The values in the table represent the minimum time durations allowed for specified voltage excursion thresholds.
4. The boundaries assume a system frequency of 60 Hertz. When evaluating volts per hertz protection, magnitude of the high voltage boundary can be adjusted in proportion to deviations of frequency below 60 Hertz.
5. Voltages in the boundaries assume positive-sequence values.

Evaluating Protection Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating.
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
    d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection settings accounting for the actual tap settings of transformers between the generator terminals and the high side of the GSU or collector transformer.

Implementation Plan

Project 2018-04 Modifications to PRC-024-2
Reliability Standard PRC-024-3

Applicable Standard

- Reliability Standard PRC-024-3 – Generator Frequency and Voltage Protection Settings

Requested Retirement

- Reliability Standard PRC-024-2 – Generator Frequency and Voltage Protective Relay Settings

Prerequisite Standard(s)

- None

Applicable Entities

- Generator Owners that that apply protection listed in Section 4.2.1.
- Transmission Owners that own a BES generator step-up transformer or collector transformer and apply protection listed in Section 4.2.1.

Background

On November 27, 2018, the NERC Operating Committee (OC) and Planning Committee (PC) submitted a Standard Authorization Request (SAR) prepared by the Inverter-Based Resource Performance Task Force (IRPTF), which reports to the OC and PC. Project 2018-04 addresses this SAR.

In 2017, the OC and PC convened the IRPTF shortly after it became clear that inverter-based generation was dropping off-line during normally cleared Bulk Power System (BPS) line faults. The NERC IRPTF supported NERC and WECC staff in the analysis of the Blue Cut Fire and Canyon 2 Fire disturbances in southern California. From the key findings and recommendations in the reports on the analysis, the IRPTF (as a stakeholder group of industry experts) developed recommended performance characteristics from inverter-based resources connected to the BPS.

Based off the disturbance analyses and development of the PRC-024-2 Gaps Whitepaper, the IRPTF identified potential modifications to PRC-024-2 to help ensure that inverter-based generator owners, operators, developers, and equipment manufacturers understand the intent of the standard in order for their plants respond to grid disturbances in a manner that contributes to the reliable operation of the BPS.

General Considerations

This Implementation Plan includes an effective date as well as phased-in compliance dates. As detailed below, there are two compliance dates: one for Generator Owners and one for Transmission Owners.

Effective Date

Reliability Standard PRC-024-3

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is eighteen (18) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is eighteen (18) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Date for Applicable Generator Owners

Applicable Generator Owners shall comply with all Requirements upon the effective date of Reliability Standard PRC-024-3.

Compliance Date for Applicable Transmission Owners

Applicable Transmission Owners shall not be required to comply with the Requirements until forty-two (42) months after the effective date of Reliability Standard PRC-024-3.

Retirement Date

Reliability Standard PRC-024-2

Reliability Standard PRC-024-2 shall be retired immediately prior to the effective date of Reliability Standard PRC-024-3 in the particular jurisdiction in which the revised standard is becoming effective.

Project 2019-01 – Modifications to TPL-007-3 Standard Drafting Team Recommendation

Action

Appoint members, chair, and vice chair to Project 2019-01 Modifications to TPL-007-3 Standard Drafting Team (SDT), as recommended by NERC staff.

Background

Project 2019-01 will address the directives issued by FERC in Order No. 851 to modify the TPL-007 Reliability Standard. In Order No. 851, FERC directed NERC to submit modifications to: (1) require the development and implementation of corrective action plans to mitigate assessed supplemental geomagnetic disturbance event vulnerabilities (P 29); and (2) replace the corrective action plan time-extension provision in Requirement R7.4 with a process through which extensions of time are considered on a case-by-case basis (P 54).

From February 25 – March 26, 2019, NERC solicited nominations for volunteers to serve on a SDT for Project 2019-01. NERC staff received fourteen nominations from industry professionals. NERC recommends nine individuals with the requisite background, experience, and skills necessary for membership on the SDT.

Project 2018-03 Standards Efficiency Review Retirements

Action
Information

Background
The Standard Authorization Request (SAR) for Project 2018-03 Standards Efficiency Review Retirements recommended the retirement of, among other things: (i) Reliability Standard INT-010-2, in its entirety; and (ii) INT-009-2.1 Requirement R2.

In the course of implementing these recommendations and reviewing industry comments, the Project 2018-03 Standard Drafting Team (SDT) identified a need to make a minor revision to a requirement not originally identified in the SAR.

Reliability Standard INT-009-2.1 Requirement R1 references Reliability Standard INT-010-2. To avoid the potential confusion of having a reference to a retired standard in an active requirement, the SDT will remove this reference prior to posting the draft INT-009-3 standard for final ballot.

The SDT, having considered the issue, determined that removal of the INT-010 reference would be consistent with the SAR's recommendation to retire INT-010-2 and would constitute a non-substantive change that may be made prior to final ballot. The SDT further determined that removal of the INT-010 reference would result in no change to the purpose and intent of INT-009 Requirement R1.

Agenda Item 7
Standards Committee
April 17, 2019

NERC Legal and Regulatory Update

March 7, 2019 - April 2, 2019

NERC FILINGS TO FERC SUBMITTED SINCE LAST SC UPDATE

FERC Docket No.	Filing Description	FERC Submittal Date
RD19-3-000	Petition of NERC for Approval of Proposed Reliability Standard CIP-008-6 NERC submits a petition for approval of Proposed Reliability Standard CIP-008-6 (Cyber Security - Incident Reporting and Response Planning). The proposed Reliability Standard addresses FERC's directives from Order No. 848.	3/7/2019
RD09-6-003	2019 NERC Standards Report, Status and Timetable for Addressing Regulatory Directives NERC submits its 2019 NERC Standards Report, Status and Timetable for Addressing Regulatory Directives. The annual report is in accordance with Section 321.6 of the NERC Rules of Procedure.	3/29/2019

FERC ISSUANCES SINCE LAST SC UPDATE

FERC Docket No.	Issuance Description	FERC Issuance Date
RD18-3-000	Letter Order Approving the Retirement of Regional Reliability Standard PRC-004-WECC-2 FERC issues a letter order accepting NERC and WECC's joint petition (filed March 9, 2018) and the supplemental petition (filed February 11, 2019) for the approval of the retirement of regional Reliability Standard PRC-004-WECC-2 (Protection System and Remedial action Scheme Misoperation). The retirement will be effective January 1, 2021.	3/28/2019

Standards Committee Expectations

Approved by Standards Committee January 12, 2012

Background

Standards Committee (SC) members are elected by members of their segment of the Registered Ballot Body, to help the SC fulfill its purpose. According to the Standards Committee Charter, the SC's purpose is:

> *In compliance with the NERC Reliability Standards Development Procedure, the Standards Committee manages the NERC standards development process for the North American-wide reliability standards with the support of the NERC staff to achieve broad bulk power system reliability goals for the industry. The Standards Committee protects the integrity and credibility of the standards development process.*

The purpose of this document is to outline the key considerations that each member of the SC must make in fulfilling his or her duties. Each member is accountable to the members of the Segment that elected them, other members of the SC, and the NERC Board of Trustees for carrying out their responsibilities in accordance with this document.

Expectations of Standards Committee Members

1. SC Members represent their segment, not their organization or personal views. Each member is expected to identify and use mechanisms for being in contact with members of the segment in order to maintain a current perspective of the views, concerns, and input from that segment. NERC can provide mechanisms to support communications if an SC member requests such assistance.
2. SC Members base their decisions on what is best for reliability and must consider not only what is best for their segment, but also what is in the best interest of the broader industry and reliability.
3. SC Members should make every effort to attend scheduled meetings, and when not available are required to identify and brief a proxy from the same segment. Standards Committee business cannot be conducted in the absence of a quorum, and it is essential that each Standards Committee make a commitment to being present.
4. SC Members should not leverage or attempt to leverage their position on the SC to influence the outcome of standards projects.
5. The role of the Standards Committee is to manage the standards process and the quality of the output, not the technical content of standards.

Parliamentary Procedures

Based on Robert's Rules of Order, Newly Revised, 11th Edition, plus "Organization and Procedures Manual for the NERC Standing Committees"

Motions

Unless noted otherwise, all procedures require a "second" to enable discussion.

When you want to…	Procedure	Debatable	Comments
Raise an issue for discussion	Move	Yes	The main action that begins a debate.
Revise a Motion currently under discussion	Amend	Yes	Takes precedence over discussion of main motion. Motions to amend an amendment are allowed, but not any further. The amendment must be germane to the main motion, and cannot reverse the intent of the main motion.
Reconsider a Motion already approved	Reconsider	Yes	Allowed only by member who voted on the prevailing side of the original motion.
End debate	Call for the Question *or* End Debate	No	If the Chair senses that the committee is ready to vote, he may say "if there are no objections, we will now vote on the Motion." The vote is subject to a 2/3 majority approval. Also, any member may call the question. This motion is not debatable. The vote is subject to a 2/3 vote.
Record each member's vote on a Motion	Request a Roll Call Vote	No	Takes precedence over main motion. No debate allowed, but the members must approve by 2/3 majority.
Postpone discussion until later in the meeting	Lay on the Table	Yes	Takes precedence over main motion. Used only to postpone discussion until later in the meeting.
Postpone discussion until a future date	Postpone until	Yes	Takes precedence over main motion. Debatable only regarding the date (and time) at which to bring the Motion back for further discussion.
Remove the motion for any further consideration	Postpone indefinitely	Yes	Takes precedence over main motion. Debate can extend to the discussion of the main motion. If approved, it effectively "kills" the motion. Useful for disposing of a badly chosen motion that can not be adopted or rejected without undesirable consequences.
Request a review of procedure	Point of order	No	Second not required. The Chair or secretary shall review the parliamentary procedure used during the discussion of the Motion.

Notes on Motions

Seconds. A Motion must have a second to ensure that at least two members wish to discuss the issue. The "seconder" is not recorded in the minutes. Neither are motions that do not receive a second.

Announcement by the Chair. The Chair should announce the Motion before debate begins. This ensures that the wording is understood by the membership. Once the Motion is announced and seconded, the Committee "owns" the motion, and must deal with it according to parliamentary procedure.

Voting

Voting Method	When Used	How Recorded in Minutes
Unanimous Consent The standard practice.	When the Chair senses that the Committee is substantially in agreement, and the Motion needed little or no debate. No actual vote is taken.	The minutes show "by unanimous consent."
Vote by Voice	The standard practice.	The minutes show Approved or Not Approved (or Failed).
Vote by Show of Hands (tally)	To record the number of votes on each side when an issue has engendered substantial debate or appears to be divisive. Also used when a Voice Vote is inconclusive. (The Chair should ask for a Vote by Show of Hands when requested by a member).	The minutes show both vote totals, and then Approved or Not Approved (or Failed).
Vote by Roll Call	To record each member's vote. Each member is called upon by the Secretary, and the member indicates either "Yes," "No," or "Present" if abstaining.	The minutes will include the list of members, how each voted or abstained, and the vote totals. Those members for which a "Yes," "No," or "Present" is not shown are considered absent for the vote.