NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Agenda
Standards Committee Meeting

March 20, 2024 | 10:00 a.m.—3:00 p.m. Central
Hybrid

Occidental Chemical Corporation (Oxy)
5 Greenway Plaza, Suite 110
Houston, TX 77046

Dial-in: 1-415-655-0002 | Access Code: 2316 142 2251 | Meeting Password: 032024
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Introduction and Chair's Remarks

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

Agenda Items

1. **Review March 20, 2024 Agenda - Approve - *Todd Bennett* (1 minute)**
2. **Consent Agenda - Approve - *Todd Bennett* (5 minutes)**
   a. February 21, 2024 Standards Committee Meeting Minutes* - **Approve**
3. **Projects Under Development - Review**
   a. Project Tracking Spreadsheet - *Mike Brytowski* (10 minutes)
   b. Three-month outlook* - *Latrice Harkness* (5 minutes)
   c. Projected Posting Schedule - *Latrice Harkness* (5 minutes)
4. **Periodic Standards Committee Member Training - Informational**
   a. Standards Committee Charter Revisions – *Todd Bennett* (10 minutes)
   b. 2023 Standards Rules of Procedure Revisions – *Sarah Crawford* (10 minutes)
   c. 2024 Registration Rules of Procedure Revisions – *Candice Castaneda* (10 minutes)
5. **Guidance Document for Management of Remanded Interpretations – Approve – *Alison Oswald* (10 minutes)**
   a. Guidance Document for Management of Remanded Interpretations*
6. **Project 2020-02 Modifications to PRC-024 (Generator Ride-through) – Authorize – *Alison Oswald* (10 minutes)**
   a. PRC-024-4*

   b. PRC-029-1*

   c. Implementation Plan*

7. **Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues – Authorize – *Jamie Calderon* (10 minutes)**

   a. PRC-030-1*

   b. Implementation Plan*

8. **Project 2023-07 Transmission System Planning Performance for Extreme Weather – Authorize – *Jamie Calderon* (10 minutes)**

   a. TPL-008-1*

   b. Implementation Plan*

9. **High Priority Project Updates**

   a. Project 2022-03 Energy Assurance with Energy-Constrained Resources – *Ruth Kloecker* (10 minutes)

   b. Project 2023-03 Internal Network Security Monitoring – *Thad Ness and/or Valerie Ney* (10 minutes)

10. **Subcommittee Updates**

   a. Project Management and Oversight Subcommittee (PMOS) – *Mike Brytowski* (10 minutes)

   b. Standards Committee Process Subcommittee (SCPC) – *Troy Brumfield* (10 minutes)

   c. Standing Committees Coordinating Group (SCCG) – *Todd Bennett* (10 minutes)

   d. Reliability and Security Technical Committee (RSTC) – *Venona Greaff* (10 minutes)

   e. NERC Board of Trustees – *Sue Kelly* (10 minutes)

11. **Legal Update and Upcoming Standards Filings - Review - *Sarah Crawford* (5 minutes)**

12. **Informational Items – Enclosed**

   a. Standards Committee Expectations*

   b. 2024 SC Meeting Schedule

   c. 2024 Standards Committee Roster

   d. Highlights of Parliamentary Procedure*

13. **Adjournment**

*Background materials included.

Minutes
Standards Committee Meeting

T. Bennett, chair, called to order the meeting of the Standards Committee (SC or the Committee) on February 21, 2024, at 1:00 p.m. Eastern. D. Love 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
D. Love called attention to the NERC Antitrust Compliance Guidelines and the public meeting notice and directed questions to NERC's General Counsel, Sonia C. Rocha.

Introduction and Chair's Remarks
T. Bennett welcomed the Committee, guests, and proxies to the meeting.

Review February 21, 2024 Agenda (agenda item 1)
The Committee approved the February 21, 2024 meeting agenda.

Consent Agenda (agenda item 2)
The Committee approved the January 17, 2024 Standards Committee Meeting Minutes.

Projects Under Development (agenda item 3)
M. Brytowski reviewed the Project Tracking Spreadsheet. A. Oswald reviewed the Project Posting Schedule. S. Kim provided update to the Fast Track Project.

Project 2022-03 Energy Assurance with Energy-Constrained Resources SPM Deviation (agenda item 4)
A. Oswald provided an overview of the project background.

Project 2023-03 Internal Network Security Monitoring (agenda item 5)
A. Oswald provided an overview of the project background. S. Rueckert made a motion to approve a waiver of provisions of the Standard Process Manual for Project 2023-03 INSM due to regulatory deadlines, as follows:

- Additional formal comment and ballot period(s) reduced from 45 days to as few as 10 calendar days, with ballot(s) and non-binding poll(s) conducted during the last five calendar days of the comment period (Sections 4.9,4.12).

The committee approved the motion with W. Chambliss opposed and no abstentions.

Project 2022-01 Reporting ACE Definition and Associated Terms Errata (agenda item 6)
J. Calderon provided an overview of the project background. W. Chambliss made a motion to approve errata changes to the defined term "Automatic Generation Control" (AGC), to remove an apostrophe

from the word “Areas’” and to delete the words “of a”, consistent with Section 12.0 of the Standards Process Manual (SPM).

The committee approved the motion with no oppositions and no abstentions.

Legal Update and Upcoming Standards Filings (agenda item 7)
S. Crawford provided an update.

Adjournment
The meeting adjourned at 1:44 p.m. Eastern.

Standards Committee
2024 Segment Representatives

Segment and Terms	Representative	Organization	Proxy	Present (Member or Proxy)
Chair 2024-25	Todd Bennett* Managing Director, Reliability Compliance & Audit Services	Associated Electric Cooperative, Inc.		y
Vice Chair 2024-25	Troy Brumfield* Regulatory Compliance Manager	American Transmission Company		y
Segment 1-2024-25	Charlie Cook Lead Compliance Analyst	Duke Energy		y
Segment 1-2023-24	Amy Casuscelli Manager, Reliability Assurance & Risk Management	Xcel Energy		y
Segment 2-2024-25	Jamie Johnson Infrastructure Compliance Manager	California ISO		y
Segment 2-2023-24	Charles Yeung Executive Director Interregional Affairs	Southwest Power Pool		y
Segment 3-2024-25	Kent Feliks Manager NERC Reliability Assurance – Strategic Initiatives	American Electric Power Company, Inc.		y
Segment 3-2023-24	Vicki O' Leary Director – Reliability, Compliance, and Implementation	Eversource Energy		y
Segment 4-2024-25	Marty Hostler Reliability Compliance Manager	Northern California Power Agency		y
Segment 4-2023-24	Patti Metro* Senior Grid Operations & Reliability Director	National Rural Electric Cooperative Associate		y
Segment 5-2024-25	Terri Pyle* Utility Operational Compliance and NERC Compliance Office	Oklahoma Gas and Electric		y
Segment 5-2023-24	Jim Howell Sr Director, Strategy	Treaty Oak Clean Energy		y

Segment and Terms	Representative	Organization	Proxy	Present (Member or Proxy)
Segment 6-2024-25	Peter Yost Manager NERC Reliability Compliance	Con Edison Company of New York, Inc.		y
Segment 6-2023-24	Justin Welty Senior Manager, NERC Reliability Standards	NextEra Energy	Richard Vendetti	y
Segment 7-2024-25	Vacant	N/A		n/a
Segment 7-2023-24	Venona Greaff* Senior Energy Analyst	Occidental Chemical Corporation		y
Segment 8-2024-25	Robert Blohm[1] Managing Director	Keen Resources Ltd.		n
Segment 8-2023-24	Philip Winston Retired (Southern Company)	Independent		n
Segment 9-2024-25	Paul MacDonald Director Reliability Standards, Compliance and Enforcement	New Brunswick Energy and Utilities Board		y
Segment 9-2023-24	William Chambliss General Counsel	Virginia State Corporation Commission		y
Segment 10-2024-25	Dave Krueger Senior Program Manager, Operations	SERC Reliability Corporation		y
Segment 10-2023-24	Steven Rueckert Director of Standards	WECC		y

[1] Serving as Canadian Representative
*Denotes SC Executive Committee Member

3 Month Outlook

April	
Accept/Authorize SAR - SC Action	**Posting Information**
Setting Planner/Operator Data Sharing Requirements	SARs associate with Milestone 3 from order 901. Due date of November 2025
Data Aggregation for non-registered generation	
IBR Model Validation	
Revise modeling projects for IBR	
Authorize Initial Posting - SC Action	
2023-06 CIP-014 Risk Assessment Refinement	**TBD**
Additional Ballot Postings	
2021-03 CIP-002	**Week of April 1**
2023-03 Internal Network Security Monitoring (INSM)	**Week of April 8**
Final Ballot Postings	
2016-02 Modifications to CIP Standards	**Week of April 1**
2023-03 Internal Network Security Monitoring (INSM)	**Week of April 22**
May	
Additional Ballot Postings	
2020-02 Modifications to PRC-024	**Week of May 6**
2022-03 Energy Assurance with Energy-Constrained Resources	TBD
June	
Additional Ballot Postings	
2020-02 Modifications to PRC-024	**Week of June 3**
2020-06 Verifications of Models and Data for Generators	**TBD**
2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues	**TBD**
Final Ballot Postings	
2023-04 Modifications to CIP-003	TBD

Standards Resource Documents Periodic Review

Action
Approve the following revised Standards Resource Document as recommended by the Standards Committee Process Subcommittee (SCPS):

- Guidance Document for Management of Remanded Interpretations Approved by the Standards Committee

Background
A subgroup of SCPS conducted a periodic review of a Standards Resource Document, specifically, a Guidance Document for Management of Remanded Interpretations that was approved by the Standards Committee. As part of this process, NERC staff updated the template for the document. The SCPS subgroup recommended a minor clarifying change to the content of the one document listed above. Specifically, the SCPS subgroup recommended that the word “should” be replaced with “will” in the following:

> If the Interpretation will be redeveloped, the SC ~~should~~ will also decide whether to assign the Interpretation to the existing interpretation drafting team, or whether to dismiss the existing interpretation drafting team and assign the project to a new interpretation drafting team.

On February 20, 2024, the SCPS endorsed the subgroup's proposed revisions and recommended them for Standards Committee (SC) approval.

Summary

NERC staff and the SCPS recommend that the SC approve the proposed revisions to the document.

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Guidance Document for Management of Remanded Interpretations

Approved by the Standards Committee

This document provides guidance regarding the management of Interpretations that have been remanded by an Applicable Governmental Authority.

In the event an Applicable Governmental Authority issues an order remanding a proposed Interpretation, NERC Legal and NERC Reliability Standards staff will consult with the original requestor regarding whether further action is necessary to provide clarity on the issue.

- If the requestor provides written notice that further action is not necessary, then NERC Legal and Standards staff will report the decision to the other Applicable Governmental Authorities. A copy of the communication will be provided to: (1) the Standards Committee (SC); (2) the Regional Entities; and (3) the original requestor of the Interpretation. If the SC determines that there is an outstanding issue, it may submit a new Request for Interpretation or Standard Authorization Request pursuant to the NERC Standard Processes Manual (SPM).
- If the requestor provides written notice requesting further action to provide clarity on the issue, then NERC Legal and NERC Standards staff will evaluate the remand order as soon as is practicable and will make a recommendation to the SC regarding whether the Interpretation should be redeveloped or whether the applicable standard(s) should be revised.
  - The SC will decide whether the Interpretation should be redeveloped as soon as is practicable or the applicable standard(s) should be revised and will document the basis of this decision. This decision is a procedural decision only and is not a substantive decision based on the technical content of the Interpretation.
  - If the Interpretation will be redeveloped, the SC will also decide whether to assign the Interpretation to the existing interpretation drafting team, or whether to dismiss the existing interpretation drafting team and assign the project to a new interpretation drafting team. The Interpretation will be redeveloped in accordance with the SPM. If a new Interpretation request is required, it shall be reviewed by NERC Standards and NERC Legal staff to ensure that the request is consistent with Section 7.0 of the NERC SPM.
  - If the Interpretation will not be redeveloped or the applicable standard(s) will be revised in lieu of redeveloping the interpretation, the SC will dismiss the existing interpretation drafting team.
  - If the SC determines that revisions to the applicable Reliability Standard(s) are necessary, a Standard Authorization Request may be submitted by any entity or individual, including NERC committees or subgroups and NERC staff, to initiate development pursuant to the NERC SPM.

- Once the SC has made a decision regarding the procedural status of the Interpretation, NERC shall report the decision to the other Applicable Governmental Authorities. A copy of the communication will be provided to: (1) the SC; (2) the Regional Entities; and (3) the original requestor of the Interpretation.

The SC will refer any compliance questions arising from the remand to the Compliance & Certification Committee.

Version History

Version	Date	Owner	Change Tracking
1	April 19, 2014	Standards Information Staff	Approved by Standards Committee
2	January 18, 2017	Standards Information Staff	Periodic review; clarifying updates made.
3	September 18, 2019	Standards Information Staff	Periodic review; clarifying updates made.
4	May 17, 2022	Standards Information Staff	Removed footnote for clarification
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Project 2020-02 Modifications to PRC-024 (Generator Ride-Through)

Action

Authorize initial posting of proposed Reliability Standard(s) PRC-024-4, PRC-029-1, and the associated Implementation Plan for a 25-day formal comment period, with ballot pools formed in the first 10 days and parallel initial ballots and non-binding polls on the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), conducted during the last 10 days of the comment period.

Background

The goal of Project 2020-02 is to mitigate the ongoing and systemic performance issues identified across multiple Interconnections and across many disturbances analyzed by NERC and the Regions. These issues have been identified in Inverter-Based Resources (IBR) and synchronous generators, with many causes of tripping entirely unrelated to voltage and frequency protection settings as dictated by the currently effective version of PRC-024-3. Reliability Standard PRC-024-4 includes revisions to the applicability to synchronous generators and synchronous condensers. PRC-029-1 is presented as a new ride-through Reliability Standard with applicability to inverter-based resources.

At the April 19, 2023 Standards Committee (SC) meeting, the SC accepted the revised SAR submitted by the Project 2020-02 Drafting Team. In October 2023, FERC issued Order No. 901, which directed NERC to develop new or modified existing Reliability Standards that include new requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance. Project 2020-02 was one of three projects identified by NERC that must be completed and filed with FERC by November 4, 2024 to address Order No. 901 directives. At the December 2023 SC meeting, the SC approved waivers for Project 2020-02, allowing formal comment periods to be reduced from 45 days to 25 calendar days, and final ballot periods to be reduced from 10 days to as few as 5 calendar days.

A Quality Review (QR) for this Project was performed from February 20 – 28, 2024. The QR team consisted of Lauren Perotti (NERC Legal), Jon Hoffman (NERC Legal), Amy Engstrom (NERC Enforcement), Farzaneh Tafreshi (NERC Enforcement), James McGrane (NERC Enforcement), Ryan Mauldin (NERC Compliance Assurance), Stephen Solis (ERCOT), John Schmall (ERCOT), Maysam Radvar (KLS Power Consulting), Kristine Martz (EEI), and Donna Oikarinen (American Transmission Company).

Summary

NERC staff recommends that the SC authorize a 25-day formal comment period for PRC-024-4, PRC-029-1, and the associated Implementation Plan, with ballot pools formed in the first 10 days and parallel initial ballots and non-binding polls on the VRFs and VSLs conducted during the last 10 days of the comment period.

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-024-4 is posted for a 25-day formal comment period with initial ballot.

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023

Anticipated Actions	Date
25-day formal comment period with initial ballot	March 25, 2024 - April 19, 2024
15-day formal comment period and additional ballot	April 29, 2024 - May 14, 2024
Final Ballot	May 20 - 25, 2024
Board adoption	August 14, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

A. Introduction

1. **Title:** Frequency and Voltage Protection Settings for Synchronous Generators and Synchronous Condensers

2. **Number:** PRC-024-4

3. **Purpose:** To assure that protection of synchronous generators and synchronous condensers do not cause tripping during defined frequency and voltage excursions in support of the Bulk Power System (BPS).

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Generator Owners that apply protection listed in Sections 4.2.1 or 4.2.2.

4.1.2. Transmission Owners that apply protection listed in Section 4.2.2.

4.1.3. Transmission Owners (in the Quebec Interconnection only) that own a BES generator step-up (GSU) transformer or main power transformer (MPT)[1] and apply protection listed in Section 4.2.1.

4.1.4. Planning Coordinators (in the Quebec Interconnection only)

4.2. Facilities[2]:

4.2.1 Frequency, voltage, and volts per hertz protection (whether provided by relaying or functions within associated control systems) that respond to electrical signals and: (i) directly trip the generating resource(s); or (ii) provide signals to the generating resource(s) to trip; and are applied to the following:

4.2.1.1 Bulk Electric System (BES) synchronous generators.

4.2.1.2 BES GSU transformer(s) for synchronous generators.

4.2.1.3 High-side of the synchronous generator-connected unit auxiliary transformer[3] (UAT) installed on BES generating resource(s).

4.2.1.4 Elements that are designed primarily for the delivery of capacity from multiple synchronous generators connecting to a common bus identified in the BES Definition, Inclusion I4, to the point where those resources aggregate to greater than 75 MVA.

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[1] For the purpose of this standard, the MPT is the power transformer that steps up voltage from multiple small synchronous generators, e.g. multiple small hydro generators connecting to a common bus.

[2] It is not required to install or activate the protections described in Facilities Section 4.2.

[3] These transformers are variously referred to as station power UAT, or station service transformer(s) used to provide overall auxiliary power to the synchronous generators. This UAT is the transformer connected on the generator bus between the low side of the GSU and the generator terminal.

4.2.1.5 MPT of multiple synchronous generators connecting to a common bus as identified in the BES Definition, Inclusion I4.

4.2.2 Frequency, voltage, and volts per hertz protection (whether provided by relaying or functions within associated control systems) that respond to electrical signals and: (i) directly trip transmission connected synchronous condensers; or (ii) provide signals to trip transmission connected synchronous condenser and are applied to the following:

4.2.2.1 BES synchronous condensers

4.2.2.2 BES step-up transformer(s) for synchronous condensers.

4.2.2.3 High-side of the synchronous condenser-connected unit auxiliary transformer (UAT).

4.2.3 **Exemptions:** Protection on all auxiliary equipment within the synchronous generator or synchronous condenser Facility.

5. **Effective Date:** See Implementation Plan for PRC-024-4

B. Requirements and Measures

R1. Each Generator Owner and Transmission Owner shall set applicable frequency protection[4] in accordance with PRC-024 Attachment 1 such that the applicable protection does not cause the synchronous generator(s) or condenser(s) to trip within the "no trip zone" during a frequency excursion with the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Applicable frequency protection may be set to trip within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M1. Each Generator Owner and 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 and Transmission Owner shall set applicable voltage protection[5] in accordance with PRC-024 Attachment 2, such that the applicable protection does not cause the synchronous generator(s) or condenser(s) to trip within the "no trip zone" during a voltage excursion at the high-side of the GSU or MPT, 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.
- Applicable voltage protection may be set to trip during a voltage excursion within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M2. Each Generator Owner and 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 and Transmission Owner shall document each known regulatory or equipment limitation[6] that prevents an applicable synchronous generator(s) or condenser(s) with 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]*

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[4] Frequency, voltage, and volts per hertz protection (whether provided by relaying or functions within associated control systems) that respond to electrical signals and: (i) directly trip the synchronous generator(s) or condenser(s); or (ii) provide signals to the synchronous generator(s) or condenser(s) to trip.
[5] Ibid.
[6] Excludes limitations caused by the setting capability of the frequency, voltage, and volts per hertz protective relays for the synchronous generator(s) or condenser(s). This does not exclude limitations originating in the equipment protected by the relay.

3.1. The Generator Owner and 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 and 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 and Transmission Owner shall provide its applicable protection settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated synchronous generator(s) or condenser(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 and Transmission Owner shall have evidence that it communicated applicable 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 and Transmission Owner shall keep data or evidence of Requirements R1 through R4 for five 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 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 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 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 Transmission Planner within 120 calendar

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				days of identifying the limitation.
R4.	The Generator Owner or Transmission Owner provided its 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 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 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 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 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 or provided 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 protection settings within 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner failed to provide protection settings within 150 calendar days of a written request.

D. Regional Variances

D.A. Variance for the Quebec Interconnection

This Variance replaces Requirement R2 of the continent-wide standard in its entirety and adds a new requirement, Requirement D.A.5., applicable to Planning Coordinators in the Quebec Interconnection.

This Variance replaces continent-wide Requirement R2 in its entirety with the following:

D.A.2. Each Generator Owner and Transmission Owner shall set applicable voltage protection[6] in accordance with PRC-024 Attachment 2B, such that the applicable protection does not cause the synchronous generator(s) or condenser(s) to trip within the "no trip zone" during a voltage excursion at the high-side of the GSU or MPT, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- For newly designated strategic power plants, applicable protections must comply with the high voltage durations for such plants within 48 calendar months of the notification made pursuant to Requirement D.A.5. During this transition period, voltage protections must at least comply with the high voltage durations for "all power plants".
- Synchronous generator(s) are permitted to be set to trip during a voltage excursion bounded by the "no trip zone" of PRC-024 Attachment 2B for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- If the Transmission Planner allows less stringent voltage protection settings than those required to meet PRC-024 Attachment 2B, then the Generator Owner or Transmission Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.

M.D.A.2. Each Generator Owner and 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.

This Variance adds the following Requirement:

D.A.5 Each Planning Coordinator shall designate, at least once every five calendar years, the strategic power plants that must comply with Attachment 2B and notify, within 30 calendar days of its designation, each Generator Owner or Transmission Owner that owns facilities[7] in the

[7] Facilities in the strategic power plants include facilities with synchronous generator(s) from the generator up to and including the MPT or GSU.

strategic power plants. *[Violation Risk Factor: Medium] [Time Horizon: Long-term planning]*

M.D.A.5 Each Planning Coordinator shall have evidence that it designated, at least once every five calendar years, strategic power plants in accordance with Requirement D.A.5, Part 5 and shall have dated evidence that each Generator Owner or Transmission Owner has been notified in accordance with Requirement D.A.5, part 5.2. Evidence may include, but is not limited to letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

Violation Severity Levels

This Variance adds a VSL for D.A.5 and modifies the VSL for R2 as follows:

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.A.2.	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 in accordance with Requirement D.A.2. OR The Generator Owner or Transmission Owner set its applicable voltage protection in accordance with Requirement D.A.2 but, for strategic power plants, failed to do so within 48 months of notification.
D.A.5.	N/A	The Planning Coordinator designated strategic power plants at least once every five calendar years but notified each Generator Owner or Transmission Owner that owns facilities in the strategic power plants between 31 days and 45 days after its designation.	The Planning Coordinator designated strategic power plants at least once every five calendar years but notified each Generator Owner or Transmission Owner that owns facilities in the strategic power plants between 46 days and 60 days after its designation.	The Planning Coordinator failed to designate, at least once every five years, the strategic power plants that must comply with Attachment 2B. OR The Planning Coordinator failed to notify, each Generator Owner or Transmission Owner that owns facilities in the strategic power plants or notified them more than 60 days after its designation.

E. Associated Documents

Implementation Plan

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.
3	February 6, 2020	Adopted by the NERC Board of Trustees	Standard revised in Project 2018-04
3	July 9, 2020	FERC Letter Order approved PRC024-3. Docket No. RD20-7-000	
3	July 17, 2020	Effective Date	10/1/2022

Attachment 1

(Frequency No Trip Boundaries by Interconnection[8])

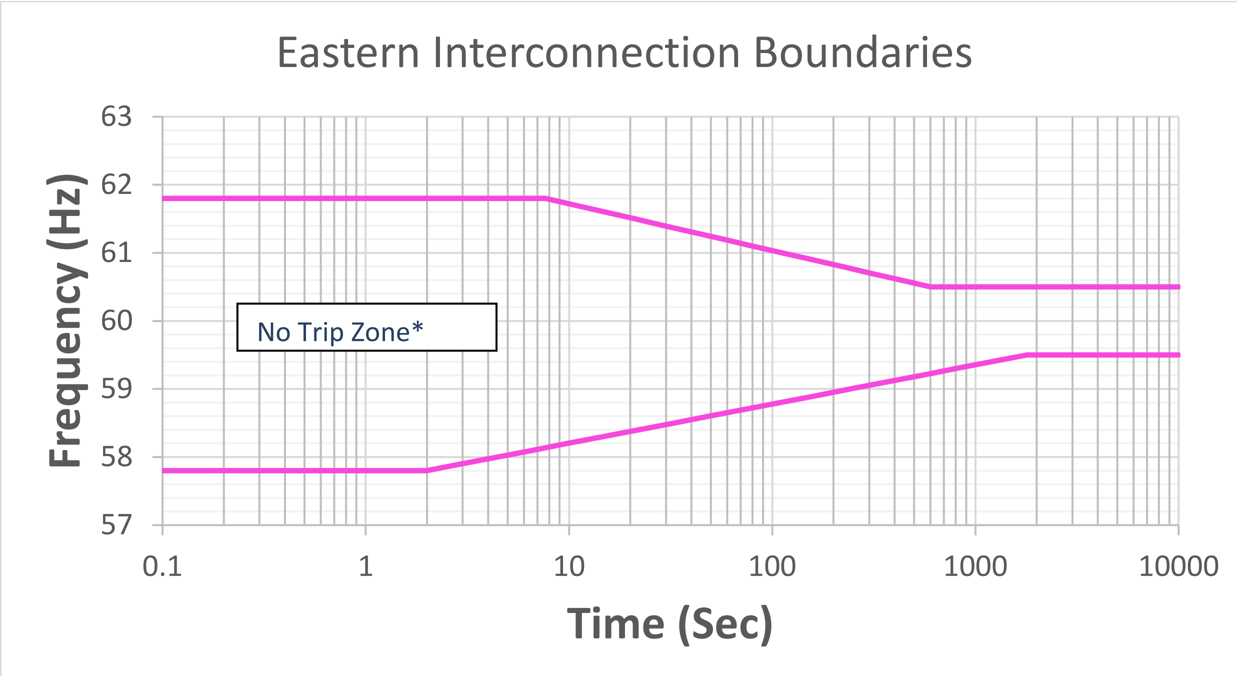

Figure 1.1

**** The area outside the "No Trip Zone" is not a "Must Trip Zone."***

Frequency Boundary Data Points – Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (sec)
≥61.8	Instantaneous[9]	≤57.8	Instantaneous[11]
≥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 1.2

[8] The figures do not visually represent the “no trip zone” boundaries before 0.1 seconds and after 10,000 seconds. The Frequency Boundary Data Points Table defines the entirety of the “no trip zone” boundaries.

[9] Frequency is calculated over a window of time. While the frequency boundaries include the option to trip instantaneously for frequencies outside the specified range, this calculation should occur over a time window. Typical window/filtering lengths are three to six cycles (50 – 100 milliseconds). Instantaneous trip settings based on instantaneously calculated frequency measurement is not permissible.

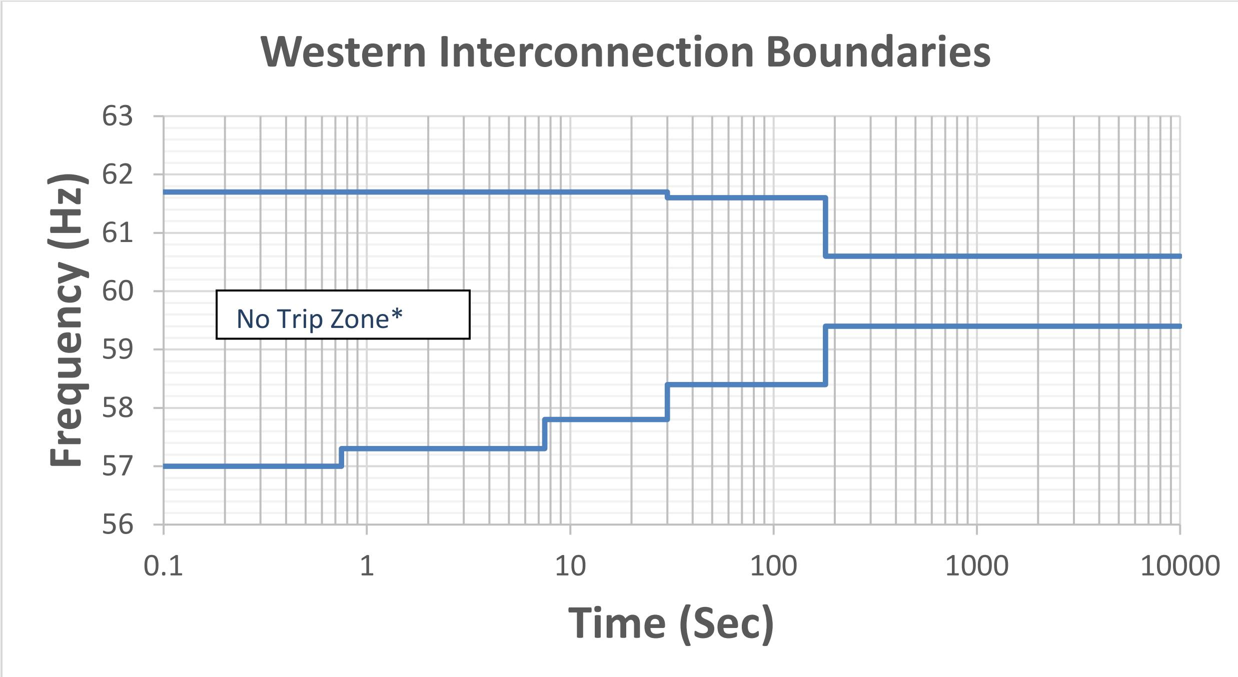

Figure1.3

**** The area outside the "No Trip Zone" is not a "Must Trip Zone."***

Frequency Boundary Data Points – Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Minimum Time (Sec)**	**Frequency (Hz)**	**Minimum Time (sec)**
≥61.7	Instantaneous[11]	≤57.0	Instantaneous[11]
≥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 1.4

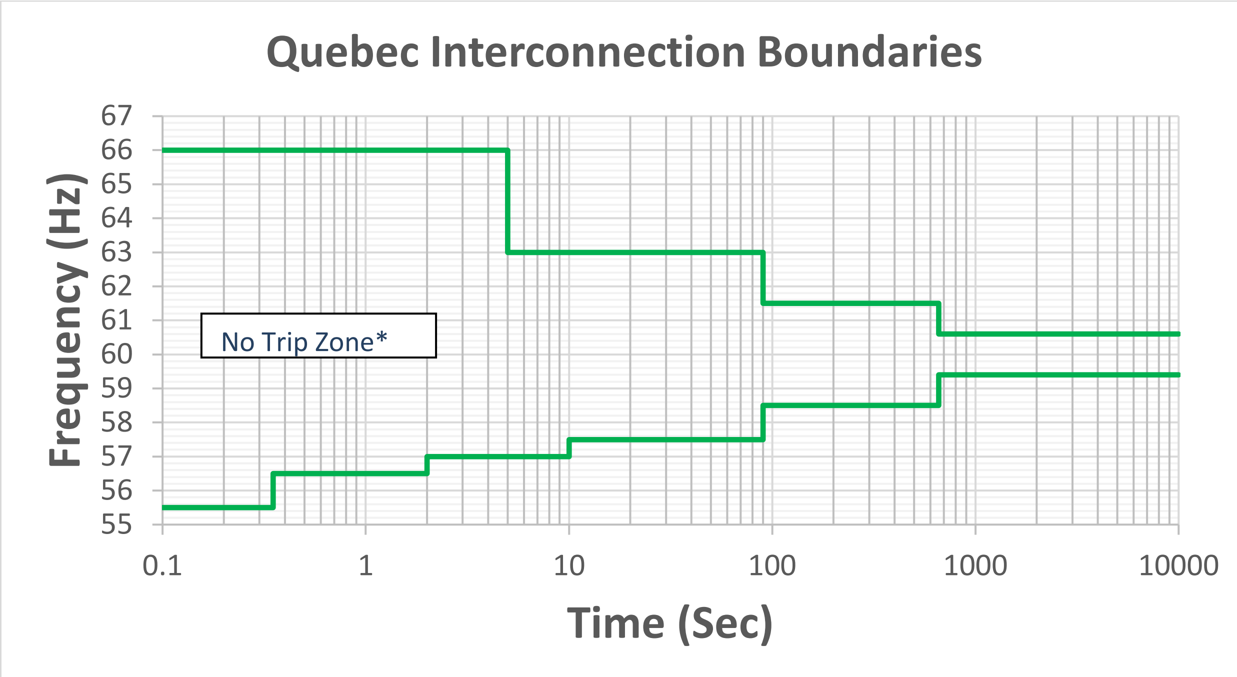

Figure 1.5

**** The area outside the "No Trip Zone" is not a "Must Trip Zone."***

Frequency Boundary Data Points – Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Minimum Time (Sec)**	**Frequency (Hz)**	**Minimum Time (Sec)**
>66.0	Instantaneous[11]	<55.5	Instantaneous[11]
≥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 1.6

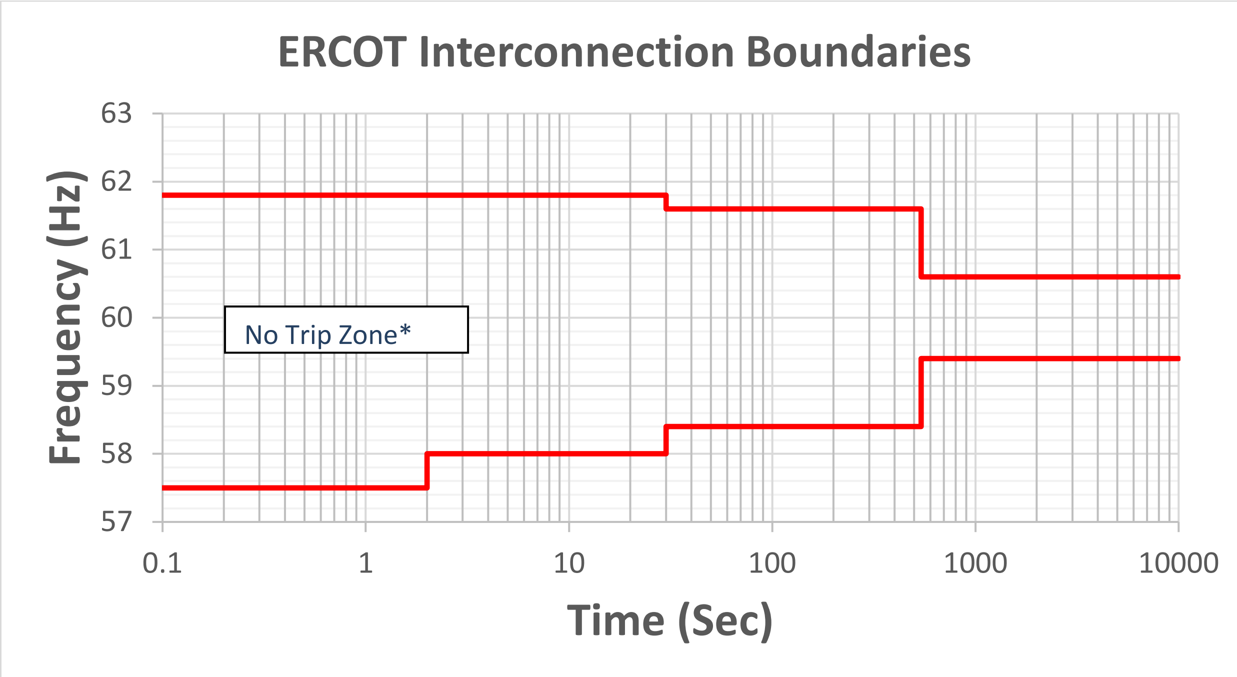

Figure 1.7

**** The area outside the "No Trip Zone" is not a "Must Trip Zone."***

Frequency Boundary Data Points – ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Minimum Time (Sec)**	**Frequency (Hz)**	**Minimum Time (sec)**
≥61.8	Instantaneous[11]	≤57.5	Instantaneous[11]
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

Table 1.8

PRC-024 — Attachment 2

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

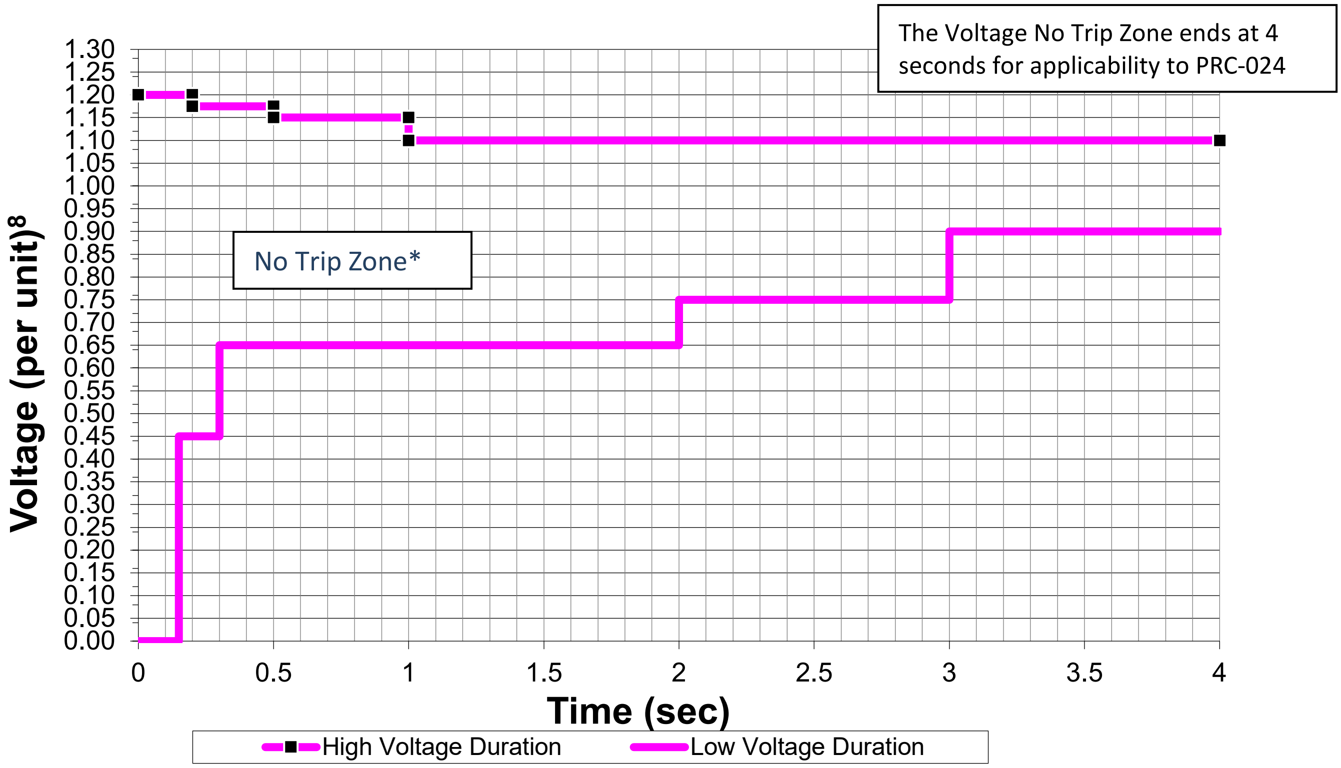

Figure 2.1

**** The area outside the "No Trip Zone" is not a "Must Trip Zone."***

Voltage Boundary Data Points

High Voltage Duration		Low Voltage Duration	
Voltage (per unit)	**Minimum Time (sec)**	**Voltage (per unit)**	**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 2.2

[8]Voltage at the high-side of the GSU or MPT.

Attachment 2A: Voltage Boundary Clarifications – Eastern, Western, and ERCOT Interconnections

Boundary Details:

1. Unless otherwise specified by the Transmission Planner, the per unit voltage base for these boundaries is the nominal transmission system voltage (e.g., 100 kV, 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, 400 kV, 500 kV, 765 kV, etc.).
2. The values in the table represent the minimum time durations allowed for specified voltage excursion thresholds.
3. When evaluating volts per hertz protection, either assume a system frequency of 60 Hertz or the magnitude of the high voltage boundary can be adjusted in proportion to deviations of frequency below 60 Hertz.
4. Voltages in the boundaries assume RMS fundamental frequency phase-to-ground or phase-to-phase per unit voltage.
5. For applicability to PRC-024, the "no trip zone" ends at 4 seconds.

Evaluating Protection Settings:

The voltage values in the Attachment 2 voltage boundaries are voltages at the high-side of the GSU/MPT. For resources with multiple stages of step up to reach interconnecting voltage, this is the high-side of the transformer with a low side below 100kV and a high-side 100kV or above**.** When evaluating protection settings, consider the voltage differences between where the protection is measuring voltage and the high-side of the GSU/MPT. A steady state calculation or dynamic simulation may be used.

If using a steady state calculation or dynamic simulation, use the following conditions when evaluating protection settings:

a. The most probable real and reactive loading conditions for the unit under study.
b. All installed generating plant reactive support (e.g., static VAR compensators, synchronous condensers, capacitors) equipment is available and operating normally.
c. Account for the actual tap settings of transformers between the generator terminals and the high-side of the GSU/MPT.
d. For dynamic simulations, the automatic voltage regulator is in automatic voltage control mode with associated limiters in service.

PRC-024— Attachment 2B

(Voltage No-Trip Boundaries – Quebec Interconnection)

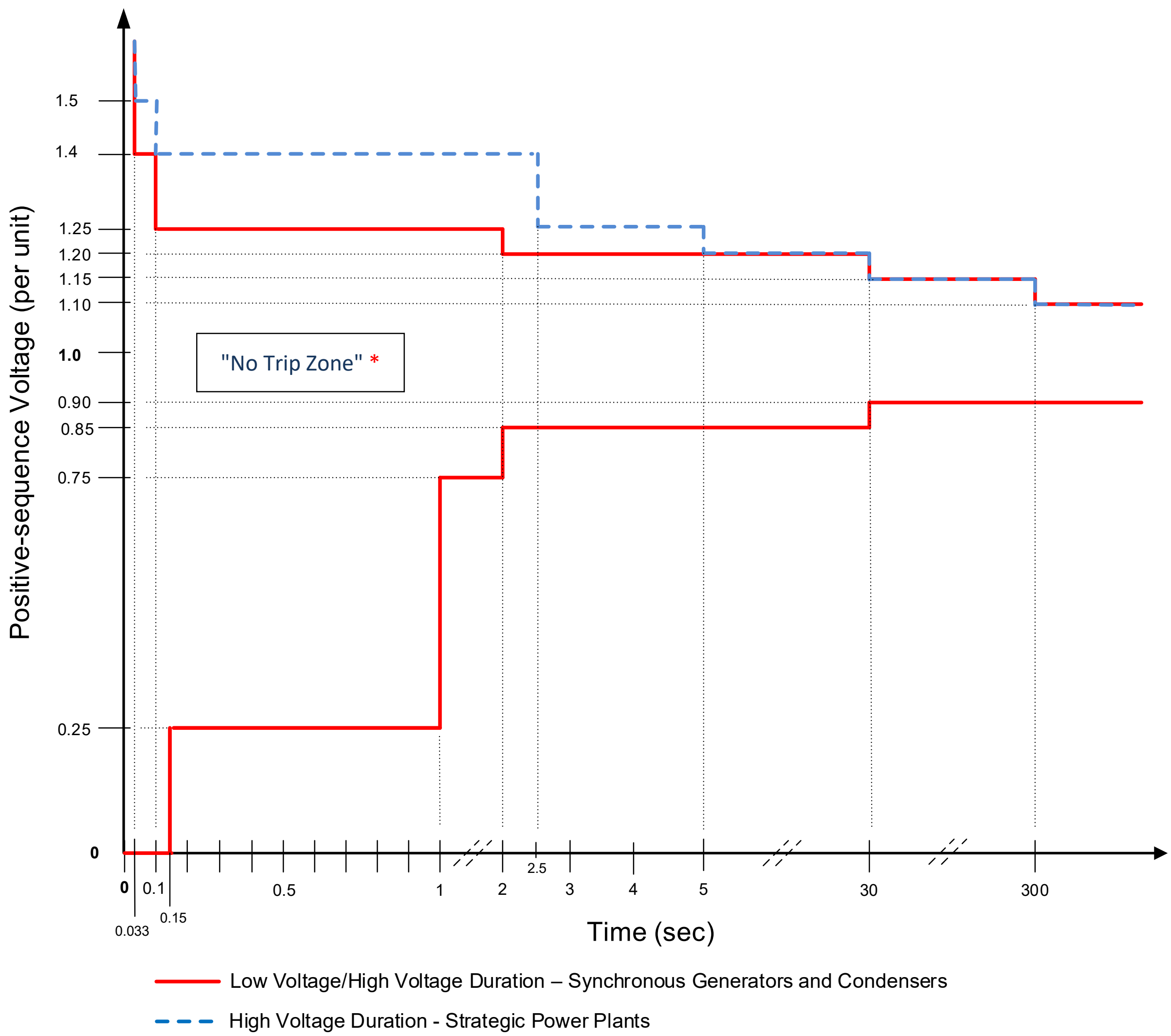

Figure 1

**** The area outside the “No Trip Zone” is not a “Must Trip Zone.”***

Voltage Boundary Data Points – Quebec Interconnection

High Voltage Duration for all Synchronous Generators and Condensers		High Voltage Duration for strategic[1] Power Plants	
Voltage (per unit)	Minimum Time (sec)	Voltage (per unit)	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 Synchronous Generators and Condensers			
Voltage (per unit)	Minimum Time (sec)		
<0.25	0.15		
<0.75	1.00		
<0.85	2.00		
<0.90	30		
≥0.90	continuous		

Table 2

Attachment 2C: Voltage Boundary Clarifications – Quebec Interconnection

Boundary Details:

1. The per unit voltage base for these boundaries is the nominal operating voltage (e.g., 120 kV, 161 kV, 230 kV, 315 kV, 735 kV, etc.).
2. The values in the table represent the minimum time durations allowed for specified voltage excursion thresholds.
3. When evaluating volts per hertz protection, either assume a system frequency of 60 Hertz or the magnitude of the high voltage boundary can be adjusted in proportion to deviations of frequency below 60 Hertz.
4. Voltages in the Quebec Interconnection boundaries assume positive-sequence values.

Evaluating Protection Settings:

The voltage values in the Attachment 2B voltage boundaries are voltages at the high-side of the GSU/MPT. For resources with multiple stages of step up to reach interconnecting voltage, this is the high-side of the transformer that connects to the interconnecting voltage. When evaluating protection settings, consider the voltage differences between where the protection is measuring voltage and the high-side of the GSU/MPT. A steady state calculation or dynamic simulation may be used.

If using a steady state calculation or dynamic simulation, use the following conditions when evaluating protection settings:

a. The most probable real and reactive loading conditions for the unit under study.
b. All installed generating plant reactive support (e.g., static VAR compensators, synchronous condensers, capacitors) equipment is available and operating normally.
c. Account for the actual tap settings of transformers between the generator terminals and the high-side of the GSU/MPT.
d. For dynamic simulations, the automatic voltage regulator is in automatic voltage control mode with associated limiters in service.

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-024-4 is posted for a 25-day formal comment period with initial ballot.

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023

Anticipated Actions	Date
25-day formal comment period and initial ballot	March 25 - April 19, 2024
15-day formal comment period and additional ballot	April 29 – May 14, 2024
Final Ballot	May 20 – May 25, 2024
Board adoption	August 14, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

A. Introduction

1. **Title:** Frequency and Voltage Protection Settings for ~~Generating Resources~~Synchronous Generators and Synchronous Condensers

2. **Number:** PRC-024-4~~3~~

3. **Purpose:** To ~~set~~ assure that protection of ~~S~~synchronous ~~G~~generators and ~~S~~synchronous ~~C~~condensers ~~generating resource(s)~~ ~~remain connected~~ do~~es~~ not cause tripping during defined frequency and voltage excursions in support of the Bulk ~~Electric System~~Power System (B~~E~~PS).

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Generator Owners that apply protection listed in Sections 4.2.1 or 4.2.2.

~~4.1.1.~~**4.1.2.** Transmission Owners that apply protection listed in Section 4.2.2.

~~4.1.2.~~**4.1.3.** Transmission Owners (in the Quebec Interconnection only) that own a BES generator step-up (GSU) transformer or main power transformer (MPT)[1] and apply protection listed in Section 4.2.1.

~~4.1.3.~~**4.1.4.** Planning Coordinators (in the Quebec Interconnection only)

4.2. Facilities[2]:

4.2.1 Frequency, voltage, and volts per hertz protection (whether provided by relaying or functions within associated control systems) that respond to electrical signals and: (i) directly trip the generating resource(s); or (ii) provide signals to the generating resource(s) to ~~either~~ trip ~~or cease injecting current~~; and are applied to the following:

4.2.1.1 Bulk Electric System (BES) synchronous generators~~generating resource(s)~~.

4.2.1.2 BES GSU transformer(s) for synchronous generators.

4.2.1.3 High-~~-~~side of the synchronous generator-connected unit auxiliary transformer[3] (UAT) installed on BES generating resource(s).

[1] For the purpose of this standard, the MPT is the power transformer that steps up voltage from multiple small synchronous generators, e.g. multiple small hydro generators connecting to a common bus. ~~the collection system voltage to the nominal transmission/interconnecting system voltage for dispersed power producing resources.~~

[2] It is not required to install or activate the protections described in Facilities Section 4.2.

[3] These transformers are variously ~~ably~~ referred to as station power UAT, or station service transformer(s) used to provide overall auxiliary power to the ~~generating resource(s)~~synchronous generators. This UAT is the transformer connected on the generator bus between the low side of the GSU and the generator terminal.

~~**4.2.1.4** Individual synchronous generators utilized as dispersed power producing resource(s) identified in the BES Definition, Inclusion I4.~~

~~4.2.1.5~~**4.2.1.4** Elements that are designed primarily for the delivery of capacity from ~~the individualispersed power producing resources~~ multiple synchronous generators connecting to a common bus identified in the BES Definition, Inclusion I4, to the point where those resources aggregate to greater than 75 MVA.

4.2.1.5 MPT[4] of multiple synchronous generators connecting to a common bus ~~utilized as dispersed power producing resources resource(s)~~ as identified in the BES Definition, Inclusion I4.

4.2.2 Frequency, voltage, and volts per hertz protection (whether provided by relaying or functions within associated control systems) that respond to electrical signals and: (i) directly trip tranmission connected synchronous condensers; or (ii) provide signals to trip transmission connected synchronous condenser and are applied to the following:

4.2.2.1 BES synchronous condensers

4.2.2.2 BES step-up transformer(s) for synchronous condensers.

~~4.2.1.6~~**4.2.2.3** High-~~-~~side of the synchronous condenser-connected unit auxiliary transformer~~5~~ (UAT).

~~4.2.2~~**4.2.3** **Exemptions:** Protection on all auxiliary equipment within the synchronous generator or synchronous condenser ~~generating~~ Facility.

5. **Effective Date:** See Implementation Plan for PRC-024-~~4~~3

~~[4] For the purpose of this standard, the MPT is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for dispersed power producing resources.~~

~~[5] These transformers are variably referred to as station power UAT, or station service transformer(s) used to provide overall auxiliary power to the synchronous condenser~~

B. Requirements and Measures

R1. Each Generator Owner and Transmission Owner shall set ~~its~~ applicable frequency protection[6] in accordance with PRC-024 Attachment 1 such that the applicable protection does not cause the ~~generating~~ synchronous generator(s) or condenser(s) to trip ~~or cease injecting current~~ within the "no trip zone" during a frequency excursion with the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Applicable frequency protection may be set to trip ~~or cease injecting current~~ within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M1. Each Generator Owner and 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 and Transmission Owner shall set ~~its~~ applicable voltage protection[7] in accordance with PRC-024 Attachment 2, such that the applicable protection does not cause the ~~generating resource~~ synchronous generator(s) or condenser(s) -to trip ~~or cease injecting current~~ within the "no trip zone" during a voltage excursion at the high-side of the GSU or MPT, 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.
- Applicable voltage protection may be set to trip ~~or cease injecting current~~ during a voltage excursion within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M2. Each Generator Owner and 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.

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[6] Frequency, voltage, and volts per hertz protection (whether provided by relaying or functions within associated control systems) that respond to electrical signals and: (i) directly trip the ~~generating resource(s)~~ synchronous generator(s) or condenser(s); or (ii) provide signals to the ~~generating resource(s)~~ synchronous generator(s) or condenser(s) to ~~either~~ trip ~~or cease injecting current~~.

[7] Ibid.

R3. Each Generator Owner and Transmission Owner shall document each known regulatory or equipment limitation[8] that prevents an applicable ~~generating resource(s)~~ synchronous generator(s) or condenser(s) with 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 and 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 and 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 and Transmission Owner shall provide its applicable protection settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated ~~generating resource(s)~~ synchronous generator(s) or condenser(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 and Transmission Owner shall have evidence that it communicated applicable 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.

[8] Excludes limitations caused by the setting capability of the frequency, voltage, and volts per hertz protective relays for the ~~generating resource(s)~~ synchronous generator(s) or condenser(s). This does not exclude limitations originating in the equipment protected by the relay. ~~This also does not exclude limitations of frequency, voltage, and volts per hertz protection embedded in control systems~~.

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 and Transmission Owner shall keep data or evidence of Requirements R1 through R4 for ~~3~~five 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

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.	communicate the 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 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 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 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 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 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 or provided 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 protection settings within 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner failed to provide protection settings within 150 calendar days of a written request.

D. Regional Variances

D.A. Variance for the Quebec Interconnection

~~This Variance extends the applicability of Requirements R1, R3, and R4 to Transmission Owners in the Quebec Interconnection that own a BES GSU or MPT and apply protection listed in Section 4.2.1, Facilities.~~ This Variance ~~also~~ replaces Requirement R2 of the continent-wide standard in its entirety and adds a new requirement, Requirement D.A.5., applicable to Planning Coordinators in the Quebec Interconnection.

~~In Requirements R1, R3, and R4, all references to "Generator Owner" are replaced with "Generator Owner and Transmission Owner."~~

This Variance replaces continent-wide Requirement R2 in its entirety with the following:

D.A.2. Each Generator Owner and Transmission Owner shall set ~~its~~ applicable voltage protection[6~~5~~] in accordance with PRC-024 Attachment 2B~~a~~, such that the applicable protection does not cause the ~~generating resource~~synchronous generator(s) or condenser(s) to trip ~~or cease injecting current~~ within the "no trip zone" during a voltage excursion ~~within the "no trip zone"~~ at the high-~~-~~side of the GSU or MPT, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- For newly designated strategic power plants, applicable protections must comply with the high voltage durations for such plants within 48 calendar months of the notification made pursuant to Requirement D.A.5. During this transition period, voltage protections must at least comply with the high voltage durations for "all power plants".
- ~~The generating resource(s)~~Synchronous generator(s) are permitted to be set to trip ~~or to cease injecting current~~ during a voltage excursion bounded by the "no trip zone" of PRC-024 Attachment 2B~~a~~ for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- If the Transmission Planner allows less stringent voltage protection settings than those required to meet PRC-024 Attachment 2B~~a~~, then the Generator Owner or Transmission Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.
- ~~Inverter-based resources voltage protection settings may be set to cease injecting current momentarily during a voltage excursion at the high side of the MPT, bounded by the "no trip zone" of PRC-024 Attachment 2a, 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 at the high side of the MPT.~~
- ~~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 positive-sequence voltage drops back below the 1.25 p.u. at the high side of the MPT.~~

M.D.A.2. Each Generator Owner and 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.

This Variance adds the following Requirement:

D.A.5 Each Planning Coordinator shall designate, at least once every five calendar years, the strategic power plants that must comply with Attachment 2B~~a~~ and notify, within 30 calendar days of its designation, each Generator Owner or Transmission Owner that owns facilities[9] in the strategic power plants. *[Violation Risk Factor: Medium] [Time Horizon: Long-term planning]*

M.D.A.5 Each Planning Coordinator shall have evidence that it designated, at least once every five calendar years, strategic power plants in accordance with Requirement D.A.5, Part 5 and shall have dated evidence that each Generator Owner or Transmission Owner has been notified in accordance with Requirement D.A.5, part 5.2. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

[9] Facilities in the strategic power plants include facilities with synchronous generator(s) from the generator up to and including the MPT or GSU.

Violation Severity Levels

This Variance adds a VSL for D.A.5 and modifies the VSL for R2 as follows:

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.A.2.	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~~ in accordance with Requirement D.A.2. OR The Generator Owner or Transmission Owner set its applicable voltage protection in accordance with Requirement D.A.2 but, for strategic power plants, failed to do so within 48 months of notification.
D.A.5.	N/A	The Planning Coordinator designated strategic power plants at least once every five calendar years but notified each Generator Owner or Transmission Owner that owns	The Planning Coordinator designated strategic power plants at least once every five calendar years but notified each Generator Owner or Transmission Owner that owns	The Planning Coordinator failed to designate, at least once every five years, the strategic power plants that must comply with Attachment 2B~~a~~.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		facilities in the strategic power plants between 31 days and 45 days after its designation.	facilities in the strategic power plants between 46 days and 60 days after its designation.	OR The Planning Coordinator failed to notify, each Generator Owner or Transmission Owner that owns facilities in the strategic power plants or notified them more than 60 days after the its designation.

E. Associated Documents

Implementation Plan

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.
3	February 6, 2020	Adopted by the NERC Board of Trustees	Standard revised in Project 2018-04
3	July 9, 2020	FERC Letter Order approved PRC024-3. Docket No. RD20-7-000	
3	July 17, 2020	Effective Date	10/1/2022

Attachment 1

(Frequency No Trip Boundaries by Interconnection[10])

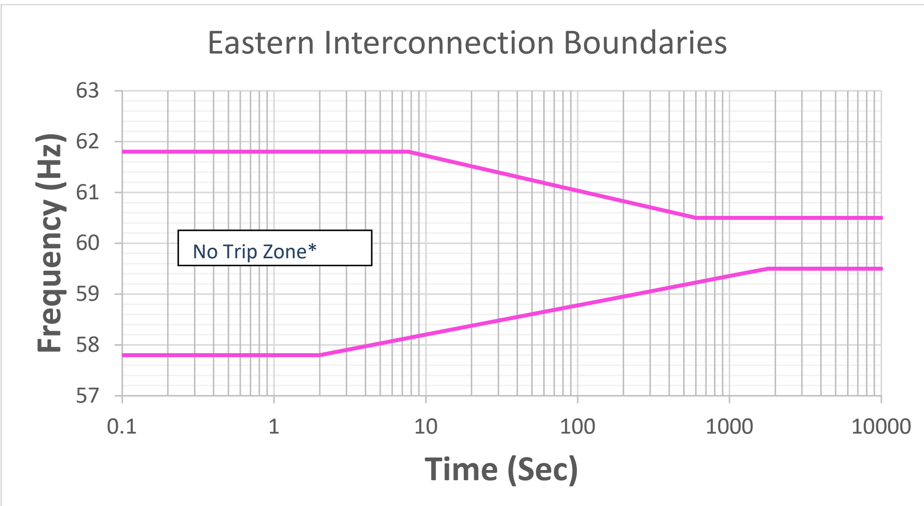


Figure 1.1

**** The area outside the "No Trip Zone" is not a "Must Trip Zone."***

Frequency Boundary Data Points – Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Minimum Time (Sec)**	**Frequency (Hz)**	**Minimum Time (sec)**
≥61.8	Instantaneous[11]	≤57.8	Instantaneous[11]
≥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 1.2

[10] The figures do not visually represent the "no trip zone" boundaries before 0.1 seconds and after 10,000 seconds. The Frequency Boundary Data Points Table defines the entirety of the "no trip zone" boundaries.

[11] Frequency is calculated over a window of time. While the frequency boundaries include the option to trip instantaneously for frequencies outside the specified range, this calculation should occur over a time window. Typical window/filtering lengths are three to six cycles (50 – 100 milliseconds). Instantaneous trip settings based on instantaneously calculated frequency measurement is not permissible.

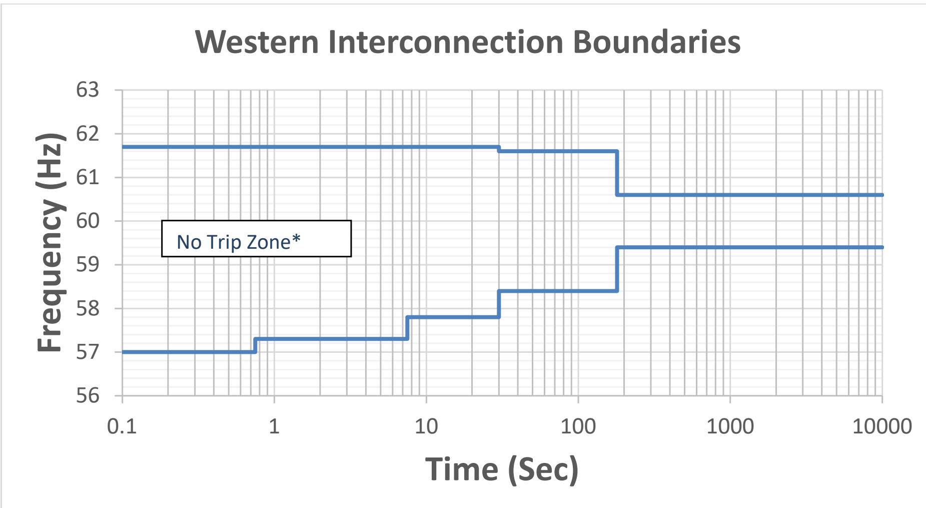


Figure ~~2~~1.3

**** The area outside the "No Trip Zone" is not a "Must Trip Zone."***

Frequency Boundary Data Points – Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Minimum Time (Sec)**	**Frequency (Hz)**	**Minimum Time (sec)**
≥61.7	Instantaneous[11]	≤57.0	Instantaneous[11]
≥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 ~~2~~1.4

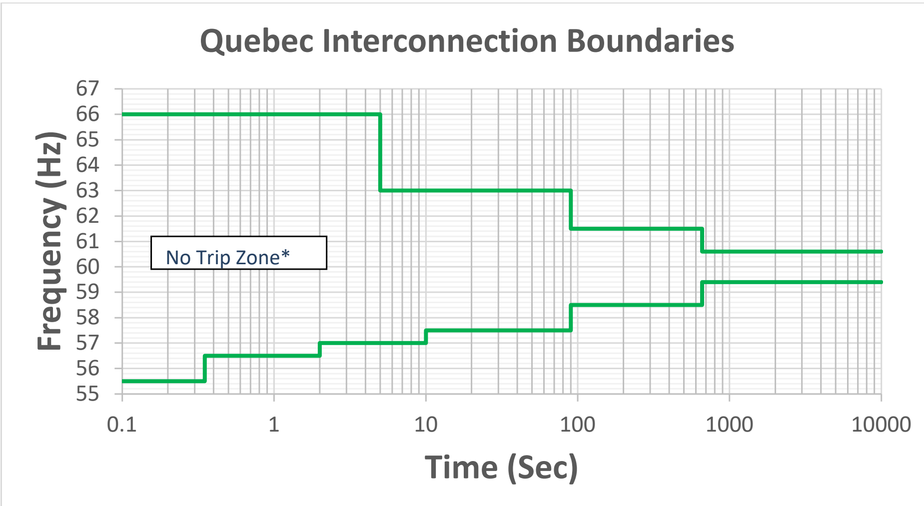


Figure ~~3~~1.5

**** The area outside the "No Trip Zone" is not a "Must Trip Zone."***

Frequency Boundary Data Points – Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Minimum Time (Sec)**	**Frequency (Hz)**	**Minimum Time (Sec)**
>66.0	Instantaneous[11]	<55.5	Instantaneous[11]
≥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 ~~3~~1.6

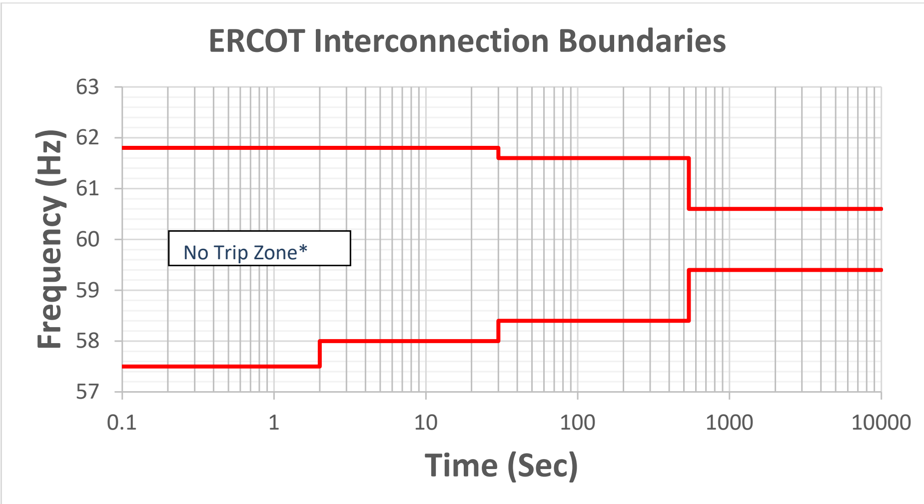


Figure ~~4~~1.7

The area outside the "No Trip Zone" is not a "Must Trip Zone."

Frequency Boundary Data Points – ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Minimum Time (Sec)**	**Frequency (Hz)**	**Minimum Time (sec)**
≥61.8	Instantaneous[11]	≤57.5	Instantaneous[11]
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

Table ~~4~~1.8

PRC-024 — Attachment 2

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

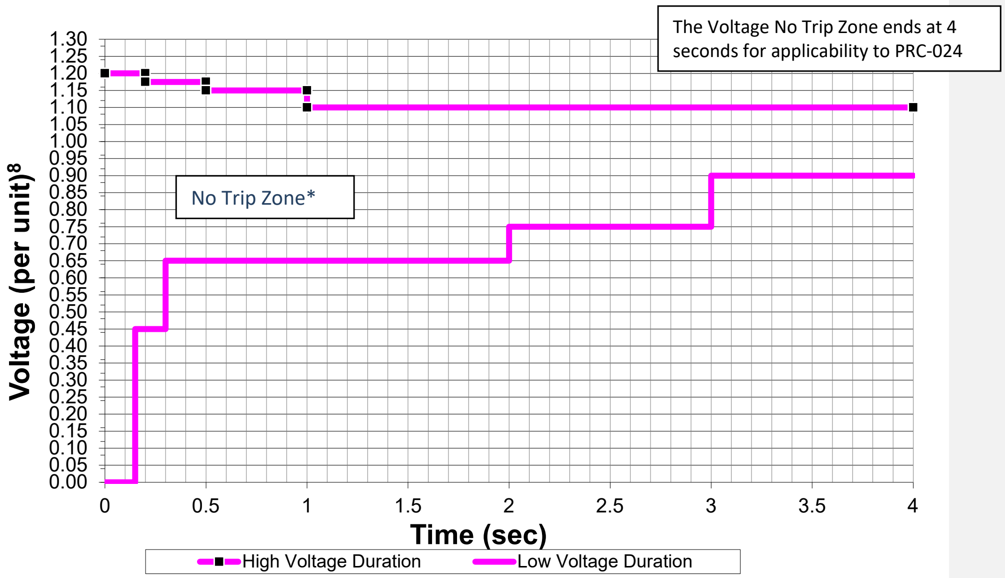


Figure 2.1

***** *The area outside the "No Trip Zone" is not a "Must Trip Zone."***

Voltage Boundary Data Points

High Voltage Duration		Low Voltage Duration	
Voltage (per unit)	**Minimum Time (sec)**	**Voltage (per unit)**	**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~~2.2

[8]Voltage at the high-side of the GSU or MPT.

Attachment 2A: Voltage Boundary Clarifications – Eastern, Western, and ERCOT Interconnections

Boundary Details:

1. Unless otherwise specified by the Transmission Planner, the per unit voltage base for these boundaries is the nominal transmission system voltage (e.g., 100 kV, 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, 400 kV, 500 kV, 765 kV, etc.).
2. The values in the table represent the minimum time durations allowed for specified voltage excursion thresholds.
3. When evaluating volts per hertz protection, either assume a system frequency of 60 Hertz or the magnitude of the high voltage boundary can be adjusted in proportion to deviations of frequency below 60 Hertz.
4. Voltages in the boundaries assume RMS fundamental frequency phase-to-ground or phase-to-phase per unit voltage.
5. For applicability to PRC-024, the "no trip zone" ends at 4 seconds.

Evaluating Protection Settings:

The voltage values in the Attachment 2 voltage boundaries are voltages at the high-~~-~~side of the GSU/MPT. For ~~generating~~ resources with multiple stages of step up to reach interconnecting voltage, this is the high-~~-~~side of the transformer with a low side below 100kV and a high-~~-~~side 100kV or above. When evaluating protection settings, consider the voltage differences between where the protection is measuring voltage and the high-~~-~~side of the GSU/MPT. A steady state calculation or dynamic simulation may be used.

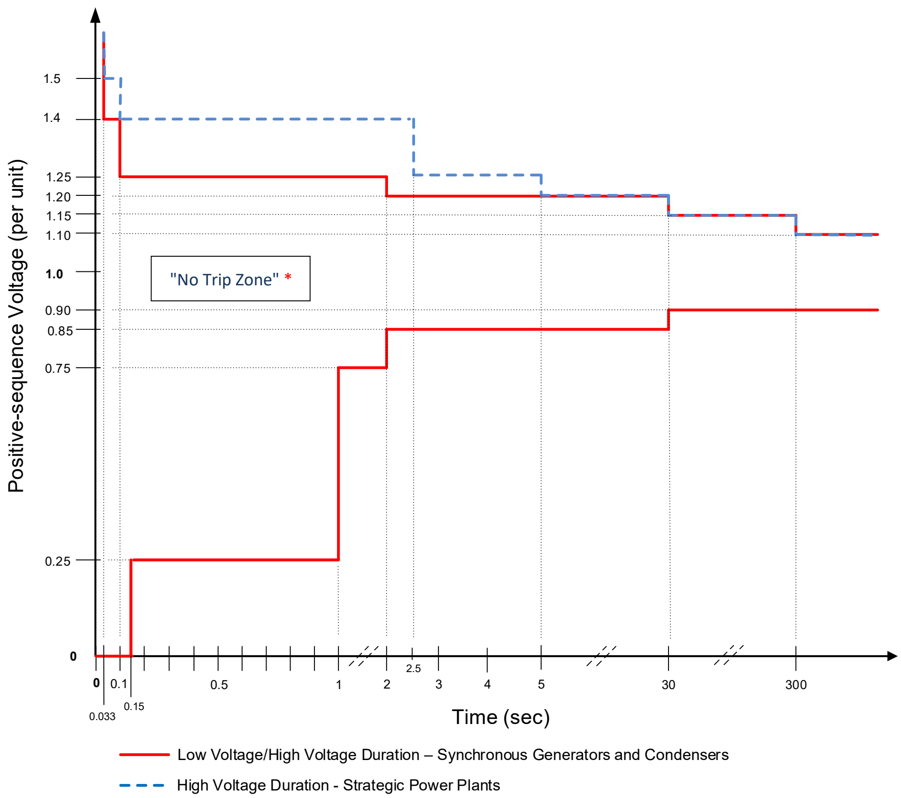
If using a steady state calculation or dynamic simulation, use the following conditions when evaluating protection settings:

a. The most probable real and reactive loading conditions for the unit under study.
b. All installed generating plant reactive support (e.g., static VAR compensators, synchronous condensers, capacitors) equipment is available and operating normally.
c. Account for the actual tap settings of transformers between the generator terminals and the high-~~-~~side of the GSU/MPT.
d. For dynamic simulations, the automatic voltage regulator is in automatic voltage control mode with associated limiters in service.

PRC-024— Attachment 2B~~a~~

(Voltage No-Trip Boundaries – Quebec Interconnection)

Field Code Changed



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-029-1 is posted for a 25-day formal comment period with initial ballot.

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023

Anticipated Actions	Date
25-day formal comment period with initial ballot	March 25 - April 19, 2024
15-day formal comment period and additional ballot	April 29 - May 14, 2024
5-day final ballot	May 20 - 25, 2024
Board adoption	August 14, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Continuous Operation Region – The range of voltages, measured at the high-side of the main power transformer, that are ≥ 0.9 per unit and ≤ 1.1 per unit.

Mandatory Operation Region – The range of voltages, measured at the high-side of the main power transformer, that are > 0.1 per unit and < 0.9 per unit – or – > 1.1 and ≤ 1.2 per unit.

Permissive Operation Region – The range of voltages, measured at the high-side of the main power transformer, that is ≤ 0.1 per unit.

A. Introduction

1. **Title:** **Frequency and Voltage Ride-through Requirements for Inverter-Based Generating Resources**
2. **Number:** **PRC-029-1**
3. **Purpose:** To ensure that Inverter-Based Resources (IBRs) remain connected and perform operationally as expected to support of the Bulk Power System (BPS) during and after defined frequency and voltage excursions.
4. **Applicability:**

4.1 Functional Entities:

4.1.1. Generator Owner

4.1.2. Transmission Owner[1]

4.2 Facilities: For purposes of this standard, the term "applicable Inverter-Based Resource" or "applicable Inverter-Based Resources" refers to the following:

4.2.1. BPS IBRs

4.2.2. IBR Registration Criteria

Effective Date: See Implementation Plan for Project 2020-02 – PRC-029-1

Standard-Only Definition: None

[1] For owners of Voltage Source Converter – High-voltage Direct Current (VSC-HVDC) transmission facilities that are dedicated connections for IBR to the BPS

B. Requirements and Measures

R1. Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that each IBR remains electrically connected and continues to exchange current in accordance with the no-trip zones and operation regions as specified in **Attachment 1** unless needed to clear a fault or a documented equipment limitation exists in accordance with **Requirement R6**. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

M1. Each Generator Owner and Transmission Owner shall have evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements, as specified in **Requirement R1**.

R2. Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that during a System disturbance, each IBR's voltage performance adheres to the following, unless a documented equipment limitation exists in accordance with **Requirement R6**. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

2.1. While the voltage at the high-side of the main power transformer remains within the Continuous Operation Region as specified in **Attachment 1**, each IBR shall:

2.1.1 Continue to deliver the pre-disturbance level of active power or available active power, whichever is less, and continue to deliver active power and reactive power up to its apparent power limit.

2.1.2 If the IBR cannot deliver both active and reactive power due to a current or apparent power limit, when the applicable voltage is below 95% and still within the Continuous Operation Region, then preference shall be given to active or reactive power according to requirements specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.2. While voltage at the high-side of the main power transformer is within the Mandatory Operation Region as specified in **Attachment 1**, each IBR shall:

2.2.1 Exchange current, up to the maximum capability while maintaining automatic voltage regulation, on the affected phases during both symmetrical and asymmetrical voltage disturbances.

2.2.2 Adjust reactive current injection at the high-side of the main power transformer so that the magnitude of the reactive current responds to changes in voltage at the high-side of the main power transformer in accordance with default reactive prioritization unless the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator specifies a certain magnitude of reactive power response to voltage changes or specifies active power priority instead of reactive power priority.

2.3. The IBR shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable **Attachment 1** Table 1 or Table 2 no-trip zone voltage thresholds and time durations in its response from Mandatory or Permissive Operation Regions to the Continuous Operating Region.

2.4. Each IBR shall restore active power output to the pre-disturbance or available level within 1.0 second when the voltage at the high-side of the main power transformer returns to the Continuous Operation Region from the Mandatory Operation Region or Permissive Operation Region (including operation in current block mode) as specified in **Attachment 1**, unless the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator specifies a lower post-disturbance active power level requirement or specifies a different post-disturbance active power restoration time.

2.5. Each IBR shall only trip to prevent equipment damage, when the voltage at the high-side of the main power transformer is outside of the no-trip zone as specified in **Attachment 1**.

M2. Each Generator Owner and Transmission Owner shall have evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to performance requirements, as specified in **Requirement R2**, during each System disturbance which has occurred within the associated Planning Coordinator(s) area(s).

R3. Each Generator Owner or Transmission Owner of an applicable IBR shall ensure that during a transient overvoltage as a result of a switching event whereby instantaneous voltage at the high-side of the main power transformer exceeds 1.2 per unit, each IBR shall either: *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

- Remain electrically connected and continue to exchange current in accordance with instantaneous transient overvoltage levels and durations specified in **Attachment 2**; or
- Remain electrically connected in current block mode in accordance with instantaneous transient overvoltage levels and durations specified in **Attachment 2**, and restart current exchange within 5 cycles of the instantaneous voltage falling below (and remaining below) 1.2 per unit.

M3. Each Generator Owner and Transmission Owner shall have evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to performance requirements, as specified in Requirement R3, during each transient overvoltage period which has occurred within the associated Planning Coordinator(s) area(s).

R4. Each Generator Owner or Transmission Owner of an applicable IBR shall ensure each IBR remains electrically connected and continues to exchange current during a frequency excursion event whereby the frequency remains within the "no trip zone" according to **Attachment 3** and the absolute rate of change of frequency (ROCOF)[2]

[2] Rate of change of frequency (ROCOF) is calculated as the average rate of change for multiple calculated system frequencies for a time period of greater than or equal to 0.1 second. ROCOF is not calculated during the fault occurrence and clearance.

magnitude is less than or equal to 5 Hz/second. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

M4. Each Generator Owner and Transmission Owner shall have evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements, as specified in Requirement R4, during each frequency excursion event which has occurred within the associated Planning Coordinator(s) area(s).

R5. Each Generator Owner or Transmission Owner of an applicable IBR shall ensure each IBR remains electrically connected and continues to exchange current during instantaneous positive sequence voltage phase angle changes that are initiated by non-fault switching events on the transmission system and are changes of less than 25 electrical degrees at the high-side of the main power transformer. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

5.1. When the instantaneous positive sequence voltage phase angle change is more than 25 electrical degrees at the high-side of the main power transformer and is initiated by a non-fault switching event on the transmission system, the IBR may trip, but shall only trip to prevent equipment damage.

M5. Each Generator Owner and Transmission Owner shall have evidence of actual recorded data or other evidence for each applicable IBR demonstrating adherence to ride-through requirements, as specified in Requirement R5, during instantaneous positive sequence voltage phase angle changes that are changes of less than 25 electrical degrees at the high-side of the main power transformer and that such changes are not initiated by non-fault switching events.

R6. Each Generator Owner and Transmission Owner with a documented equipment limitation that would prevent an applicable IBR that is in-service by the effective date of this standard from meeting voltage ride-through requirements as detailed in Requirements R1 and R2 shall communicate each equipment limitation to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s). *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1. Each Generator Owner and Transmission Owner shall include in its documentation:

6.1.1 Identifying information of the IBR (name, facility #, other)

6.1.2 Which aspects of voltage ride-through requirements that the IBR would be unable to meet

6.1.3 Identify the specific piece(s) of equipment causing the limitation

6.1.4 Information regarding any plans to repair or replace the limiting equipment that would remove the limitation (such as estimated date of repair/replacement)

6.2. Each Generator Owner and Transmission Owner with a previously communicated equipment limitation that repairs or replaces the equipment causing the limitation shall document and communicate such equipment change to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s) within 30 days of the equipment change.

M6. Each Generator Owner and Transmission Owner shall have evidence of equipment limitations, as specified in Requirement R6, documented prior to the effective date of PRC-029-1. Each Generator Owner and Transmission Owner with changes to equipment shall have evidence of communication to each associated Planning Coordinator, Transmission Planner, and Reliability Coordinator. Acceptable types of evidence may include, but are not limited to, meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence.

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.

- Each Generator Owner and Transmission Owner shall retain evidence with each requirement in this standard for five calendar years.

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 demonstrate each applicable IBR remains electrically connected and continued to exchange current in accordance with Attachment 1, unless needed to clear a fault, in accordance with Requirement R1.
R2.	N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable IBR adhered to performance requirements during each System disturbance, as specified in Requirement R2.
R3.	N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable IBR adhered to performance requirements during each transient overvoltage period as specified in Requirement R3.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable IBR adhered to performance requirements during each frequency excursion event, as specified in Requirement R4.
R5.	N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to demonstrate each applicable IBR adhered to performance requirements during each instantaneous positive sequence voltage phase angle change of less than 25 electrical degrees, as specified in Requirement R5.
R6.	The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator, Transmission Planner, and Reliability	The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator, Transmission Planner, and Reliability	The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator, Transmission Planner, and Reliability	The Generator Owner or Transmission Owner failed to document evidence of equipment limitations consistent with Requirement R6 and prior to the effective date of PRC-029-1 Requirement R6. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Coordinator more than 30 calendar days but less than or equal to 60 calendar days after the change to the equipment.	Coordinator more than 60 calendar days but less than or equal to 90 calendar days after the change to the equipment.	Coordinator more than 90 calendar days but less than or equal to 120 calendar days after the change to the equipment.	The Generator Owner or Transmission Owner with a previously communicated equipment limitation that repairs or replaces the documented limiting equipment but failed to document and communicate the change to its Planning Coordinator, Transmission Planner, and Reliability Coordinator more than 120 calendar days after the change to the equipment.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
Initial Draft	2/20/24	DRAFT	

Attachment 1: Voltage Ride-Through Criteria

Table 1: Voltage Ride-Through Requirements for AC-Connected Wind IBR

Voltage (per unit)	Minimum Ride-Through Time (sec)
≥1.200	N/A
≥1.1	1.0
≥1.05	1800
< 0.90	3.00
< 0.70	2.50
< 0.50	1.20
< 0.25	0.16
< 0.10	0.16

Table 2: Voltage Ride-Through Requirements for All Other IBR

Voltage (per unit)	Minimum Ride-Through Time (sec)
≥1.200	N/A
≥1.1	1.0
≥1.05	1800
< 0.90	6.00
< 0.70	3.00
< 0.50	1.20
< 0.25	0.32
< 0.10	0.32

1. Table 1 applies to applicable wind IBR unless connected via a dedicated VSC-HVDC transmission facility.
2. Table 2 applies to all other IBR types not covered in Table 1; including, but not limited to, the following IBR:
   a. Isolated IBR, regardless of their energy resource, interconnecting via a dedicated VSC-HVDC transmission facility.
   b. Other IBR plants or hybrid plants consisting of photovoltaic (PV) and ESS.

3. In the case of hybrid IBR consisting of wind and various other IBR technologies, the applicable table shall be based on direction by the Transmission Planner.
4. The voltage base for per unit calculation is the nominal phase-to-ground or phase-to-phase transmission system voltage unless otherwise defined by the Planning Coordinator or Transmission Planner.
5. The applicable voltage for Tables 1 and 2 is identified as the voltage max/min of phase to neutral or phase to phase fundamental root mean square (RMS) voltage at the high side of the MPT.
6. Tables 1 and 2 are only applicable when the frequency is within the no trip zone as specified in Table 3 of Attachment 3.
7. At any given voltage value, each IBR shall not trip until the time duration at that voltage exceeds the specified minimum ride-through time duration. If the voltage is continuously varying over time, it is necessary to add the duration within each band of Tables 1 and 2 over the 10-second time period to determine compliance.
8. The specified duration of the Mandatory Operation Regions and the Permissive Operation Regions in Tables 1 and 2 is cumulative over one or more disturbances within a 10 second time period.
9. The IBR may trip for more than four deviations of the applicable voltage at the high-side of the main power transformer outside of the Continuous Operation Region within any 10 second time period.
10. If the positive sequence voltage at the high-side of the main power transformer enters the Permissive Operation Region, an IBR may operate in current block mode if necessary to protect the equipment.

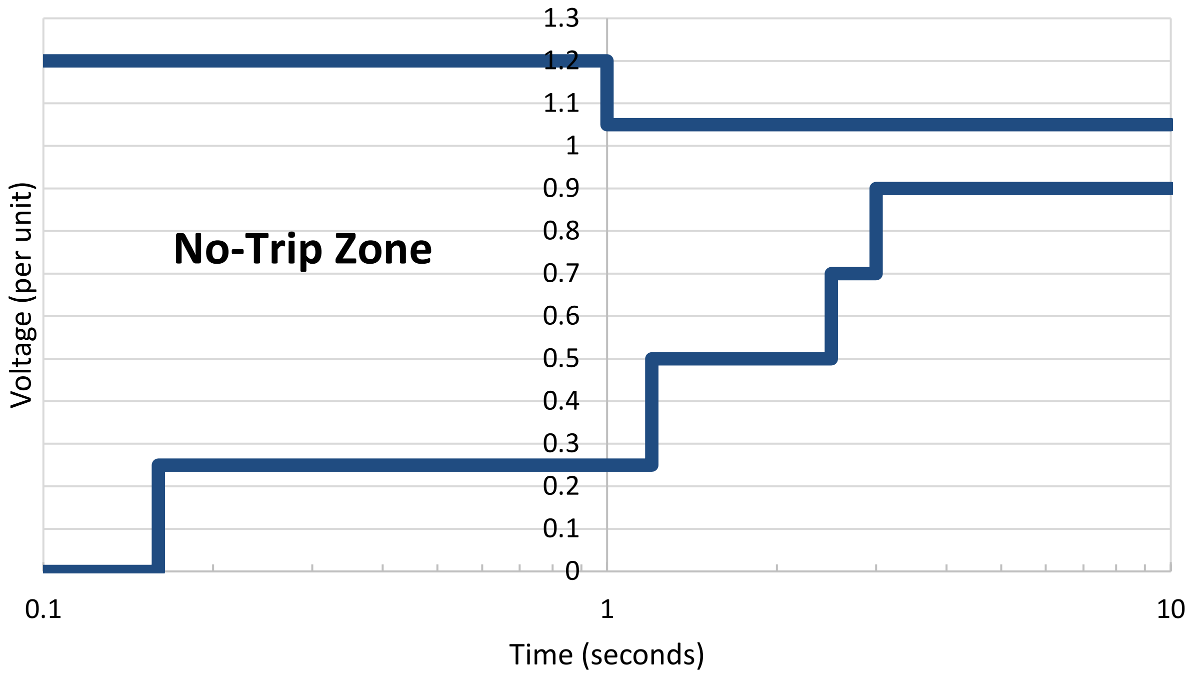


Figure 1: Voltage Ride-Through Requirements for AC-Connected Wind IBR

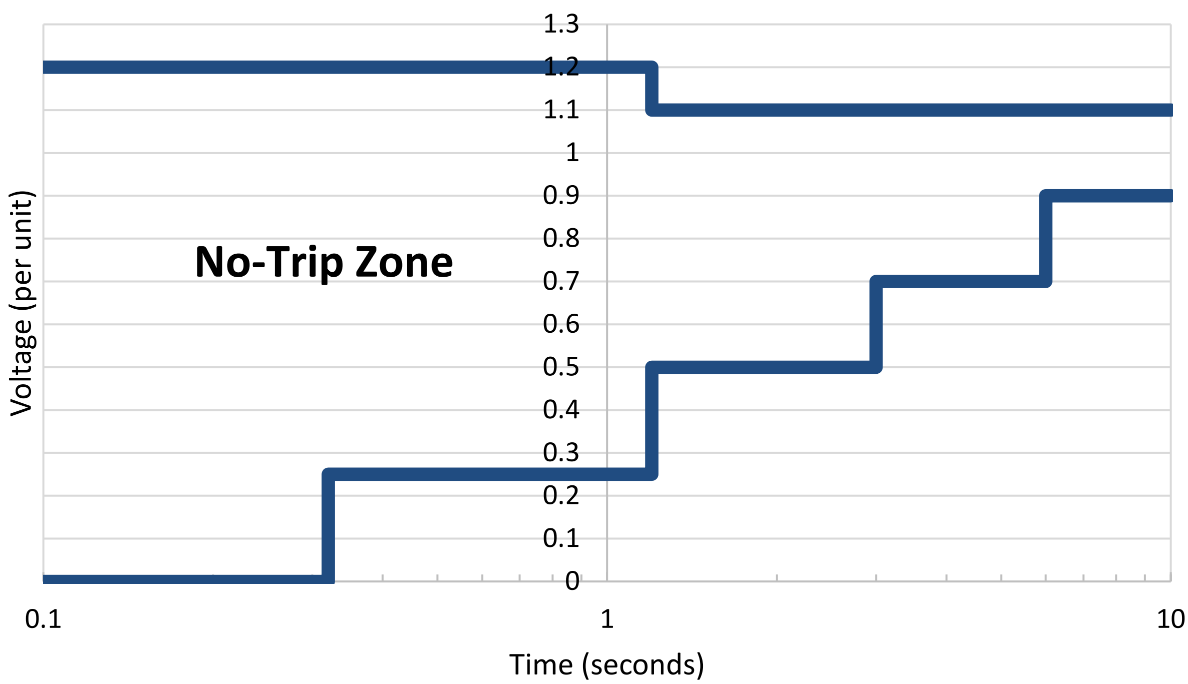


Figure 2: Voltage Ride-Through Requirements for All Other IBR

Attachment 2: Transient Overvoltage Ride-Through Criteria

Table 3: Transient Overvoltage Ride-Through Criteria

Voltage (per unit) at the high side of the MPT	Minimum Ride-Through Time (millisec)
> 1.8	May trip
> 1.7	0.2
> 1.6	1.0
> 1.4	3.0
> 1.2	15.0

1. The voltage base for per unit calculation is the nominal instantaneous phase-to-ground or phase-to-phase voltage at the high side of the MPT unless otherwise defined by the Planning Coordinator or Transmission Planner.
2. If surge protection devices are installed within the plant, the per unit voltage refers to the residual voltage with the surge arresters applied.
3. Each IBR shall not trip unless the cumulative time of one or more instances over a 1-minute time window in which the instantaneous voltage exceeds the respective voltage threshold and the minimum ride-through time.

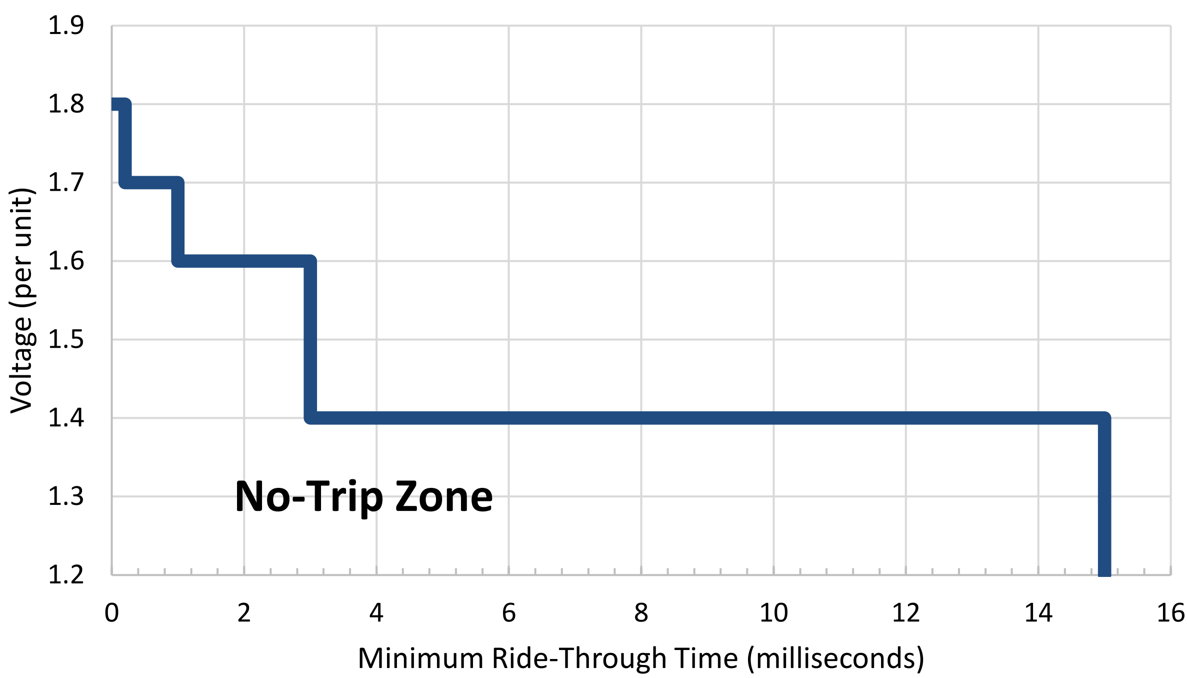


Figure 3: Transient Overvoltage Ride-Through Criteria

Attachment 3: Frequency Ride-Through Criteria

Table 4: Frequency Ride-Through Capability Requirements

Averaged System Frequency (Hz)	Minimum Ride-Through Time (sec)
≥64	May trip
≥61.8	6
> 61.5	299
> 61.2	660
< 58.8	660
< 58.5	299
< 57.0	6
< 56	May trip

1. Measurements are taken at the high-side of the main power transformer for each phase (phase to neutral).
2. Measurements are averaged over a set time period (such as 3-6 cycles) to calculate averaged system frequency at the high-side of the main power transformer.
3. Instantaneous or single points of measurement may not be used in the determination of control settings.
4. At any given frequency values, each IBR shall not trip until the time duration at that frequency exceeds the specified minimum ride-through time duration.
5. The specified durations of Table 4 are cumulative over one or more disturbances within a 15-minute time period.

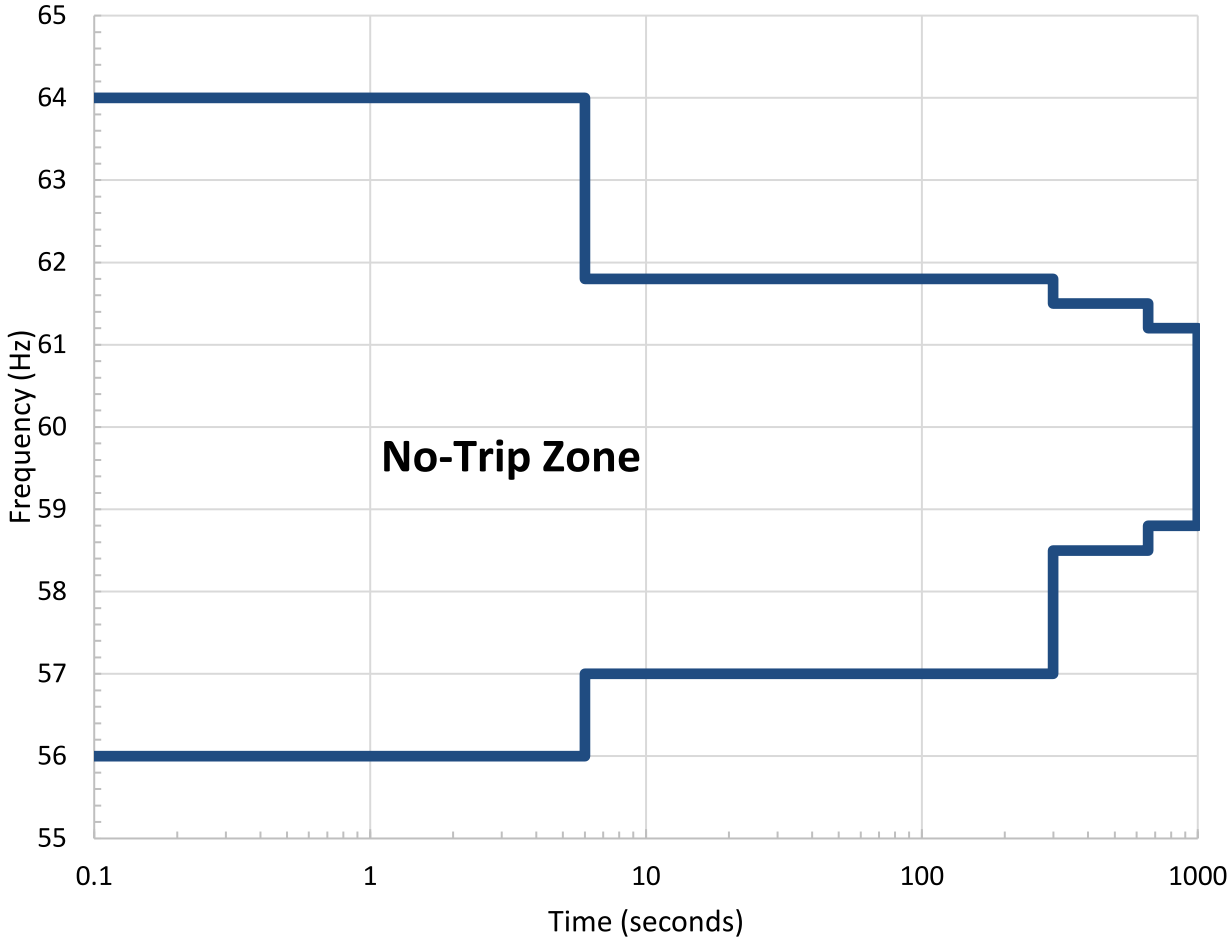


Figure 4: PRC-029 Frequency Envelopes

Implementation Plan

Project 2020-02 Modifications to PRC-024 (Generator Ride-through)
Reliability Standards PRC-024-4 and PRC-029-1

Applicable Standard(s)

- PRC-024-4 Frequency and Voltage Protection Settings for Synchronous Generators and Synchronous Condensers
- PRC-029-1 Frequency and Voltage Ride Through Requirements for Inverter-Based Generating Resources

Requested Retirement(s)

- PRC-024-3 Frequency and Voltage Protection Settings for Generating Resources

Prerequisite Standard(s)

- PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources

Proposed Definition(s)

- None

Applicable Entities

- See subject Reliability Standards.

Background

The purpose of Project 2020-02 is to modify Reliability Standard PRC-024-3 or replace it with a performance-based ride-through standard that ensures generators remain connected to the Bulk-Power System (BPS) during system disturbances. Specifically, the project focuses on using disturbance monitoring data to substantiate inverter-based resource (IBR) ride-through performance during grid disturbances. The project also ensures associated generators that fail to ride-through system events are addressed with a corrective action plan (if possible) and reported to necessary entities for situational awareness.

The purpose for this project is based on the culmination of multiple analyses conducted by the ERO Enterprise regarding widespread inverter-based resource tripping events. Furthermore, the NERC Inverter-Based Resource Performance Subcommittee[1] has developed comprehensive

[1] See documents at the NERC IRPS website: https://www.nerc.com/comm/RSTC/Pages/IRPS.aspx and the previous Inverter-Based Resource Performance Working Group website https://www.nerc.com/comm/RSTC/Pages/IRPWG.aspx

recommendations for improved performance of inverter-based resources, including the recommendation to develop comprehensive ride-through requirements.

In October 2023, FERC issued Order No. 901[2] which directs the development of new or modified Reliability Standards that include new requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance. In January 2024, NERC submitted a filing to FERC outlining a comprehensive work plan to address the directives within Order No. 901.[3] Within the work plan, NERC identified three active Standards Development projects that would need to be filed for regulatory approval with FERC by November 4, 2024. These projects include **2020-02 Modifications to PRC-024 (Generator Ride-through)**[4], **2021-04 Modifications to PRC-002-2**[5], and **2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues**[6].

Project 2020-02

Proposed Reliability Standard PRC-029-1 is a new Reliability Standard that includes ride-through requirements and performance requirements for IBRs. The scope of this project was adjusted to align with associated regulatory directives from FERC Order No. 901 and the scope of the other projects related to “Milestone 2” of the NERC work plan. The components of this project’s Standard Authorization Request (SAR) that related to the inclusions of new data recording requirements are covered in Project 2021-04 and the proposed new PRC-028-1 Reliability Standard. Components of this project’s SAR that relate to analytics and corrective actions plans are covered in Project 2023-02 and the proposed new PRC-030-1 Reliability Standard.

PRC-029-1 includes requirements for Generator Owner and Transmission Owner IBR to continue to inject current and perform frequency support during a BPS disturbance. The standard also specifically requires Generator Owner and Transmission Owner IBR to prohibit momentary cessation in the no-trip zone during disturbances.

PRC-024-4 includes modifications to revise applicable facility types to remove IBR and to include synchronous condensers.

[2] See FERC Order 901, Docket No. RM22-12-000; https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false; October 19, 2023

[3] See INFORMATIONAL FILING OF THE NORTH AMERICAN RELIABILITY CORPORATION REGARDING THE DEVELOPMENT OF RELIABILITY STANDARDS RESPONSIVE TO ORDER NO. 901 https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/NERC%20Compliance%20Filing%20Order%20No%20901%20Work%20Plan_packaged%20-%20public%20label.pdf; January 17, 2024

[4] See NERC Standards Development Project page for Project 2002-02; https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx

[5] See NERC Standards Development Project page for Project 2021-04; https://www.nerc.com/pa/Stand/Pages/Project-2021-04-Modifications-to-PRC-002-2.aspx

[6] See NERC Standards Development Project page for Project 2023-02; https://www.nerc.com/pa/Stand/Pages/Project-2023-02-Performance-of-IBRs.aspx

General Considerations

The ERO Enterprise acknowledges that there are IBRs currently in operation and unable to meet voltage ride-through requirements due to their inability to modify their coordinated protection and control settings. Consistent with FERC Order No. 901, a limited and documented exemption process for those IBR is appropriate and included within this Implementation Plan. Other NERC Standards Development projects will be pursued to address ongoing identification and mitigation of any potential reliability impacts to the BPS for such exemptions.

Effective Date and Phased-in Compliance Dates

The effective dates for the proposed Reliability Standards are provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance dates for those particular sections represent the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

PRC-024-4

Where approval by an applicable governmental authority is required, Reliability Standard PRC-024-4 shall become effective on the first day of the first calendar quarter that is 6 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 Reliability Standard PRC-024-4 shall become effective on the first day of the first calendar quarter that is 6 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

PRC-029-1

Where approval by an applicable governmental authority is required, Reliability Standard PRC-029-1 shall become effective on the first day of the first calendar quarter that is six 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 Reliability Standard PRC-029-1 shall become effective on the first day of the first calendar quarter that is six 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 PRC-029-1 - Requirement R6

Entities shall not be required to comply with Requirement R6 until six months after the effective date of Reliability Standard PRC-029-1. This compliance date is intended to assure equipment limitations have additional time to complete the equipment limitation process as outlined below.

Retirement Date

PRC-024-3

Reliability Standard PRC-024-3 shall be retired immediately prior to the effective date of Reliability Standards PRC-024-04 and PRC-029-1 in the particular jurisdiction in which the revised standard is becoming effective.

Equipment Limitations and Process for Requirement R6

Consistent with FERC Order No. 901, a limited and documented exemption for some legacy IBR with certain documented equipment limitations are acceptable. Per the Order, these IBRs are

> "…typically older IBR technology with hardware that needs to be physically replaced and whose settings and configurations cannot be modified using software updates – may be unable to implement the voltage ride though performance requirements."[7]

To assure compliance with Requirement R6 and alignment with FERC Order No. 901, only those IBR that are in operation as of the effective date of PRC-029-1 may be considered for potential exemption. Further, only those IBR that are unable to meet voltage ride-through requirements due to their inability to modify their coordinated protection and control settings may be considered for potential exemption.

Generator Owners with IBR that meet these criteria for equipment limitations must identify which of those IBR will be unable to meet voltage ride-through requirements, as described in Requirement R6. For each identified IBR, the associated Generator Owner must document:

- Identifying information of the IBR (name, facility #, other)
- Which aspects of voltage ride-through requirements that the IBR would be unable to meet
- Information regarding the limiting equipment
- Information regarding any plans to repair or replace the limiting equipment that would remove the limitation (such as estimated date of repair/replacement)

For each identified IBR, the associated Generator Owner must communicate the documented information listed above to the associated Planning Coordinator(s), Transmission Planner(s), and Reliability Coordinator(s), per the Requirement R6 no later than the effective date of Requirement R6.

[7] Order No. 901 at p. 193.

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues

Action

Authorize initial posting of proposed Reliability Standard PRC-030-1 and the associated Implementation Plan for a 25-day formal comment period, with ballot pools formed in the first 10 days and parallel initial ballots and non-binding polls on the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), conducted during the last 10 days of the comment period.

Background

Multiple NERC disturbance reports have identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults, and have elaborated on the systemic and significant BPS reliability risks that this undesired performance can pose. Project 2023-02 addresses the reliability-related need by requiring analysis and mitigation of unexpected or unwarranted protection and control operations from IBRs. This includes any types of protections and controls that result in abnormal performance issues within the plant, including abnormal performance resulting in anomalous behavior of active power output from the facility during events.

At the January 25, 2023 Standards Committee (SC) meeting, the SC accepted the Standard Authorization Request (SAR) that was submitted by the Inverter-Based Resource Performance Subcommittee and authorized soliciting members for the Drafting Team (DT). The DT was appointed at the June 21, 2023 SC meeting and a revised SAR was accepted by the SC at their October 18, 2023 meeting.

On October 19, 2023, FERC issued Order No. 901, which directed NERC to develop new or modify existing Reliability Standards that include new requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance. Project 2023-02 was one of three projects identified by NERC that must be completed and filed with FERC by November 4, 2024 to address Order No. 901 directives. At the December 2023 SC meeting, the SC approved a waiver allowing formal comment periods to be reduced from 45 days to 25 calendar days, and final ballot periods to be reduced from 10 days to as few as 5 calendar days in order to help meet the FERC- directed deadline.

The Quality Review (QR) was performed February 07 – February 20, 2024. The QR Team consisted of David Lemmons (Greybeard), Mark Gray (EEI), Jordan Mallory (NERC), Al McMeekin (NERC), Jon Hoffman (NERC Legal), and Sarah Crawford (NERC Legal).

Summary

NERC staff recommends that the SC authorize a 25-day formal comment period, with ballot pools formed in the first 10 days and parallel initial ballots and non-binding polls on the VRFs and VSLs conducted during the last 10 days of the comment period.

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-030-1 is posted for a 25-day formal comment period with initial ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 25, 2023
SAR posted for comment	February 22, 2023 – March 23, 2023

Anticipated Actions	Date
25-day formal or informal comment period with ballot	March 25, 2024
15-day formal or informal comment period with additional ballot	TBD
05-day final ballot	TBD
Board adoption	August 14 - 15, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):
None

A. Introduction

1. **Title:** Unexpected Inverter-Based Resource Event Mitigation
2. **Number:** PRC-030-1
3. **Purpose:** Identify, analyze, and mitigate unexpected Inverter-Based Resource change of power output.
4. **Applicability:**

    4.1. Functional Entities:

    4.1.1. Generator Owner

    4.2. Facilities:

    4.2.1. Bulk Power System (BPS) Inverter-Based Resources (IBR)

5. **Effective Date:** See Implementation Plan for PRC-030-1

B. Requirements and Measures

R1. Each applicable Generator Owner shall have a documented process to identify unexpected changes[1] in power output occurring within a two-second period and is the greater of either 20% of the plant's gross nameplate rating, or 20 MVA. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each applicable Generator Owner shall have evidence which may include but is not limited to: (1) a documented process for detecting unexpected changes in output as described in Requirement R1, (2) actual data recordings, and (3) identification of gross nameplate rating.

R2. Each applicable Generator Owner shall implement its process established in Requirement R1 to identify unexpected changes in power output. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence of implementation may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the applicable Generator Owner implemented its process established in Requirement R1.

R3. Each applicable Generator Owner shall provide data when requested from its Balancing Authority, Reliability Coordinator, or Transmission Operator regarding IBR responses during an identified system level event within 30 calendar days of the receipt of the request. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each applicable Generator Owner shall have evidence as specified in Requirement R3 which may include, but is not limited to, dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

R4. Each applicable Generator Owner shall analyze its IBRs performance within 45 calendar days of either the event identified pursuant to Requirement R2 or receipt of a request pursuant to Requirement R3. The analysis shall include all of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. The cause(s) of unexpected change(s) in power output;

4.2. The applicability to its other IBR facilities that could be affected by the same cause of unexpected change(s) in power output; and

4.3. Notification to each applicable Balancing Authority, Reliability Coordinator, or Transmission Operator of the analysis results.

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[1] Unexpected changes in power output includes any change of generation that is not attributed to factors such as weather patterns, change of wind, change in irradiance, curtailment, ramping, planned outage, planned testing, or the loss of a Transmission Line connecting the IBR generators.

M4. Each applicable Generator Owner shall have dated analysis documentation, developed in accordance with Requirements R4. Evidence may include, but is not limited to: (1) an analysis report, (2) actual data recordings or derivations, (3) documents describing the device specification and device configuration or settings, and (4) plant configuration.

R5. Each applicable Generator Owner shall, within 45 days of completing the analysis in Requirement R4, develop one of the following and provide it to each applicable Reliability Coordinator: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. A Corrective Action Plan (CAP) for the identified Inverter Based Resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement R4 Part 4.2; or

5.2. A technical justification that addresses why corrective actions will not be applied nor implemented.

M5. Each applicable Generator Owner shall have dated evidence (electronic or hardcopy format) that demonstrates it developed a CAP or a technical justification, and evidence of transmittal to the Reliability Coordinator in accordance with Requirement R5.

R6. Each applicable Generator Owner shall, for each of its CAPs developed pursuant to Requirement R5: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

6.1. Implement the CAP;

6.2. Update the CAP if actions or timetables change; and

6.3. Notify each applicable Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

M6. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders, maintenance records, communication with equipment manufacturers, and communication with each applicable Reliability Coordinator that documents the implementation, updating, or completion of a CAP in accordance with Requirement R5.

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 shall keep data or evidence of Requirement R1, R2, and R3, Measure M1, M2, and M3 for 12 calendar months following the completion of each Requirement.
   - The Generator Owner shall retain evidence of Requirement R4, Measure M4, including any supporting analysis per Requirements R2 and R3, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.
   - The Generator Owner shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

   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 responsible entity failed to have a documented process to identify unexpected changes in power output in accordance with Requirement R1.
R2.	N/A	N/A	N/A	The responsible entity failed to implement the process established in accordance with Requirement R1.
R3.	N/A	N/A	N/A	The responsible entity failed to provide data when requested from its Balancing Authority, Reliability Coordinator, or Transmission Operator.
R4.	The responsible entity performed an analysis in accordance with Requirement R4, but in more than 45 calendar days but less than 60 calendar days of first identifying an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R4, but in 60 or more calendar days but less than 90 calendar days of first identifying an event or receiving a request.	The responsible entity performed an analysis in accordance with Requirement R4, but in 90 or more calendar days but less than 120 calendar days of first identifying an event or receiving a request. OR The responsible entity performed the analysis in	The responsible entity developed an evaluation in accordance with Requirement R4, but in 120 calendar days or more of first identifying an event or receiving a request. OR The responsible entity performed the analysis in Requirement R4, but failed to

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			Requirement R4, but failed to address one of the Parts 4.1 through Parts 4.3.	address two or more of the Parts 4.1 through Parts 4.3 OR The responsible entity failed to develop an evaluation in accordance with Requirement R4.
R5.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 45 days, but provided within 60 days.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 60 days, but provided within 90 days.	The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented within 90 days, but provided within 120 days OR The developed CAP did not include corrective actions for other facilities owned by the GO as identified in R4.2, if necessary. OR The developed CAP or technical justification was not provided to the applicable RC.	The responsible entity developed a CAP or provide a technical justification why no corrective actions will be implemented, but in 120 calendar days or more. OR The responsible entity failed to develop a CAP or provide a technical justification why no corrective actions will be implemented.
R6.	The responsible entity implemented, but failed to update a CAP, when actions or	N/A	N/A	The responsible entity failed to implement a CAP in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	timetables changed, in accordance with Requirement R6.			accordance with Requirement R6.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan.

Version History

Version	Date	Action	Change Tracking
Initial Draft	**02/06/2024**	**Draft**	

Implementation Plan

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
Reliability Standard PRC-030-1

Applicable Standard(s)

- PRC-030-1 Unexpected Inverter-Based Resource Event Mitigation

Requested Retirement(s)

- None

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- PRC-028-1 Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources

Applicable Entities

- Generator Owner (GO)

Background

After Project 2023-02 was underway, FERC issued No. Order 901[1] that directs the development of new or modified reliability standards, including new requirements for disturbance monitoring, data sharing, post-event performance validation, and correction of IBR performance. In January 2024, NERC submitted a filing to FERC outlining a comprehensive work plan to address the directives within Order No. 901[2]. Within the work plan, NERC identified three active Standards Development Projects that would need to be filed for regulatory approval with FERC November 4th, 2024. These projects include 2020-02 Modifications to PRC-024 (Generation Ride Through)[3], 2021-04

[1] See FERC Order 901, Docket No. RM22-12-000; https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false; October 19, 2023

[2] See INFORMATIONAL FILING OF THE NORTH AMERICAN RELIABILITY CORPORATION REGARDING THE DEVELOPMENT OF RELIABILITY STANDARDS RESPONSIVE TO ORDER NO. 901 https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/NERC%20Compliance%20Filing%20Order%20No%20901%20Work%20Plan_packaged%20-%20public%20label.pdf; January 17, 2024

[3] See NERC Standards Development Project page for Project 2002-02; https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx

Modifications to PRC-002-2[4], and 2023-02 Analysis and Mitigation of BES Inverter-Based Resources Performance Issues[5].

General Considerations

The key development for applicable Functional Entities is a process to capture change in power events for IBR resources. The requested implementation timeline allows for ample time for entities to draft and implement their process. The information required for Standard compliance is currently available to Generator Owners.

Effective Date

The effective date for the proposed Reliability Standard is provided below.

Standard PRC-030-1

Where approval by an Applicable Governmental Authority is required, Reliability Standard PRC-030-1 shall become effective on the first day of the first calendar quarter that is six 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, Reliability Standard PRC-030-1 shall become effective on the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

[4] See NERC Standards Development Project page for Project 2021-04; https://www.nerc.com/pa/Stand/Pages/Project-2021-04-Modifications-to-PRC-002-2.aspx

[5] See NERC Standards Development Project page for Project 2023-02; https://www.nerc.com/pa/Stand/Pages/Project-2023-02-Performance-of-IBRs.aspx

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather

Action

Authorize initial posting of proposed Reliability Standard TPL-008-1 and its associated Implementation Plan for a 45-day formal comment period, with ballot pools formed in the first 30 days and parallel initial ballots and non-binding polls on the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), conducted during the last 10 days of the comment period.

Background

Project 2023-07 is addressing FERC Order No. 896, which directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or a new Reliability Standard, to require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of corrective action plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met.

At the July 2023 Standards Committee (SC) meeting, the SC accepted the SAR. At the December 2023 SC meeting, the SC accepted a waiver allowing formal comment periods to be reduced from 45 days to 25 calendar days and ballot periods to be reduced from 10 days to as few as five calendar days in order to help meet the FERC-directed December 2024 deadline.

The Quality Review (QR) was performed February 21 – 28, 2024. The QR Team consisted of Alan Kloster (Evergy, Inc.), Kristine Martz (EEI), Jason Chandler (ConEd), Derek Kassimer (NERC Compliance), Lauren Perotti (NERC Legal), and Jon Hoffman (NERC Legal).

Summary

NERC staff recommends that the SC authorize a 45-day formal comment period, with ballot pools formed in the first 30 days and parallel initial ballots and non-binding polls on the VRFs and VSLs conducted during the last 10 days of the comment period.

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

TPL-008-1 is posted for a 45-day formal comment and initial ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 19, 2023
SAR posted for comment	August 8 – September 27, 2023

Anticipated Actions	Date
45-day formal comment period with initial ballot	March 20 – May 3, 2024
45-day formal comment period with additional ballot	June 2024
45-day formal comment period with additional ballot	September 2024
10-day final ballot	November 2024
Board adoption	December 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Extreme Temperature Assessment – Documented evaluation of future Transmission System performance for extreme heat and extreme cold temperature benchmark events.

A. Introduction

1. **Title:** Transmission System Planning Performance Requirements for Extreme Temperature Events
2. **Number:** TPL-008-1
3. **Purpose:** Establish requirements for Transmission system planning performance for extreme heat and extreme cold temperature events
4. **Applicability:**
    - **4.1. Functional Entities:**
        - **4.1.1.** Transmission Planner
        - **4.1.2.** Planning Coordinator
5. **Effective Date:** See Implementation Plan for Project 2023-07.

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall determine and identify each entity's individual and joint responsibilities for performing the studies needed to complete the Extreme Temperature Assessment. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall provide documentation of each entity's individual and joint responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for performing the studies needed to complete the Extreme Temperature Assessment.

R2. Each responsible entity, as identified in Requirement R1, shall select one extreme heat benchmark event and one extreme cold benchmark event, from the approved benchmark library maintained by the Electric Reliability Organization (ERO), for performing the Extreme Temperature Assessment. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Each responsible entity, as identified in Requirement R1, shall have evidence in either electronic or hard copy format of its selected extreme heat benchmark event and extreme cold benchmark event for performing the Extreme Temperature Assessment.

R3. Each Planning Coordinator shall develop and implement a process for coordinating the development of benchmark planning cases among impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities based on the selected benchmark events as identified in Requirement R2. This process shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Define the planning study area boundary based on the selected benchmark events.

3.2. Modify the benchmark planning cases to include seasonal and temperature dependent adjustment for Load, generation, Transmission, and transfers which represents the selected benchmark events.

M3. Each Planning Coordinator shall provide dated evidence of a process for coordinating the development of benchmark planning cases among impacted Planning Coordinators, and Transmission Planner(s) as specified in Requirement R3. Acceptable evidence may include, but is not limited to, the following dated documentation (electronic or hardcopy format): records defining the planning study area boundary based on the selected benchmark events and modifications to the benchmark planning cases that include seasonal and temperature dependent adjustment for Load, generation, Transmission, and transfers which represent the selected benchmark events.

R4. Each responsible entity, as identified in Requirement R1, shall develop and maintain System models within its planning area for performing the Extreme Temperature Assessment. The System models shall use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, and shall represent projected System conditions based on the selected benchmark events as identified in Requirement R2. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M4. Each responsible entity, as identified in Requirement R1, shall have evidence in either electronic or hard copy format that it developed and maintained System models of the responsible entity's planning area for performing the Extreme Temperature Assessment.

R5. Each responsible entity, as identified in Requirement R1, shall have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for performing the Extreme Temperature Assessment in accordance with Requirement R3. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M5. Each responsible entity, as identified in Requirement R1, shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for performing the Extreme Temperature Assessment in accordance with Requirement R5.

R6. Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology used in the Extreme Temperature Assessment analysis to identify instability, uncontrolled separation, or Cascading. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M6. Each responsible entity, as identified in Requirement R1, shall provide dated evidence such as electronic or hard copy documentation of the defined and documented criteria or methodology used to identify instability, uncontrolled separation, or Cascading used in the Extreme Temperature Assessment analysis in accordance with Requirement R6.

R7. Each responsible entity, as identified in Requirement R1, shall identify Contingencies used in performing the Extreme Temperature Assessment for each of the event categories in Table 1 that are expected to produce more severe System impacts within its planning area. The rationale for those Contingencies selected for evaluation shall be available as supporting information. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M7. Each responsible entity, as identified in Requirement R1, shall provide dated evidence such as electronic or hard copy documentation that it has identified Contingencies for performing the Extreme Temperature Assessment for each of the event categories in Table 1 that are expected to produce more severe System impacts within its planning area and the supporting rationale, in accordance with Requirement R7, such as electronic or hard copies of documents identifying the Contingencies with supporting rationale.

R8. Each responsible entity, as identified in Requirement R1, shall complete an Extreme Temperature Assessment of the Long-Term Transmission Planning Horizon at least once every five calendar years, using the benchmark planning cases and the System models identified in Requirement R3 and R4, and the Contingencies identified in Requirement R7 for each of the event categories in Table 1, and document assumptions and results of the steady state and stability analyses. The Extreme Temperature Assessment shall include the following. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. Assessment of the benchmark planning cases developed under Requirement R4, for one of the years in the Long-Term Transmission Planning Horizon. The rationale for the year selected for evaluation shall be available as supporting information.

8.2. Sensitivity analysis to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Extreme Temperature Assessment shall include, at a minimum, changes to one of the following conditions:

- Generation;
- Real and reactive forecasted Load; or
- Transfers

M8. Each responsible entity, as identified in Requirement R1, shall provide dated evidence that it performed an Extreme Temperature Assessment, such as electronic or hard copies of the assessment, meeting all the requirements in Requirement R8.

R9. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) (CAPs) when the benchmark planning case study results indicate the System is unable to meet performance requirements for Table 1 P0 or P1 Contingencies. The responsible entities shall share their CAPs with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues. In addition, where Load shed is allowed as an element of a CAP for the Table 1 P1 Contingency, the responsible entity shall document the alternative(s) considered, as mentioned in Requirement R10, and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues. Revisions to the CAP(s) are allowed in subsequent Extreme Temperature Assessments, but the planned System shall continue to meet the performance requirements. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M9. Each responsible entity, as identified in Requirement R1, shall provide dated evidence such as electronic or hard copy documentation of a CAP, including any revision history, when the benchmark planning case study results indicate the System is unable to meet performance requirements for the Table 1 P0 or P1 Contingencies in accordance with Requirement R9.

R10. Each responsible entity, as identified in Requirement R1, shall evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the benchmark planning case study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, P5, and P7 Contingencies. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M10. Each responsible entity, as identified in Requirement R1, shall provide the dated evidence that it evaluated and documented possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the benchmark planning case study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, P5, and P7 Contingencies in accordance with Requirement R10, such as electronic or hard copies of the assessment detailing such actions.

R11. Each responsible entity, as identified in Requirement R1, shall provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M11. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient; or a demonstration of a public posting that it provided its Extreme Temperature Assessment to any functional entity who has a reliability need within 60 calendar days of a written request.

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.

- Each responsible entity shall retain evidence of compliance with each requirement in this standard for five calendar years or one complete Extreme Temperature Assessment cycle, 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.

Table 1: Contingencies and Performance Criteria						
Event	**P0**	**P1**	**P2**	**P4**	**P5**	**P7**
Facility Voltage Level of Contingency	Applicable to: • BES level 200 kV and above • Any common structure that includes a Facility 200kV and above Reference Voltages: • Non-generator step up transformer outage events, the reference voltage applies to the low-side winding. • Generator and generator step-up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the step-up transformer).					
Steady State Performance Criteria	• Applicable Facility Ratings shall not be exceeded. • System steady state voltages shall be within acceptable limits as defined in Requirement R5.	• Applicable Facility ratings shall not be exceeded • System steady state voltages shall be within acceptable limits as defined in Requirement R5.	Evaluation for uncontrolled separation or Cascading, as defined in Requirement R6.			
Stability Performance Criteria	Initialization without oscillation	Instability, uncontrolled separation, or Cascading, as defined in Requirement R6, shall not occur.	Evaluation for instability, uncontrolled separation, or Cascading, as defined in Requirement R6.			
Corrective Action Plan Required	Yes (See Requirement R9)	Yes (See Requirement R9)	No (See Requirement R10)			
Non-Consequential Load Loss Allowed	No (See Requirement R9)	Yes (See Requirement R9)	Yes			

Table 1: Contingencies and Performance Criteria			
Category	**Initial Condition**	**Event**	**Fault Type** [1]
P0 No Contingency	Normal System	None	N/A
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device[2]	3Ø
		5. Single Pole of a DC line	SLG
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [3]	N/A
		2. Bus Section Fault	SLG
		3. Internal Breaker Fault[4] (non-Bus-tie Breaker)	SLG
		4. Internal Breaker Fault (Bus-tie Breaker)[4]	SLG

Table 1: Contingencies and Performance Criteria

Category	Initial Condition	Event	Fault Type [1]
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker[5](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device[2] 5. Bus Section	SLG
		6. Loss of multiple elements caused by a stuck breaker[5] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[7] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device[2] 5. Bus Section	
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [6] 2. Loss of a bipolar DC line	SLG

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)

1. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
2. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
3. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
4. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
5. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
6. Excludes circuits that share a common structure (Planning event P7) for one mile or less.
7. For purposes of this standard, non-redundant components of a Protection System to consider are as follows:
    a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times;
    b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center);
    c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit);
    d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual and joint responsibilities for performing the required studies for the Extreme Temperature Assessment.
R2.	N/A	N/A	The responsible entity did not select an extreme heat benchmark event or extreme cold benchmark event from the ERO approved benchmark library.	The responsible entity did not select an extreme heat benchmark event and extreme cold benchmark event from the ERO approved benchmark library.
R3.	N/A	N/A	N/A	The Planning Coordinator did not develop or implement a process for coordinating the development of benchmark planning cases among impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities. OR

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				The Planning Coordinator developed and implemented a process for coordinating the development of benchmark planning cases among impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities, but this process did not define the planning study area boundary based off the selected benchmark events. OR The Planning Coordinator developed and implemented a process for coordinating the development of benchmark planning cases among impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities, but this process did not modify the benchmark planning cases to include seasonal and temperature dependent adjustments load, generation, Transmission, and transfers.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	N/A	N/A	N/A	The responsible entity did not develop or maintain System models of the responsible entity's planning area for performing Extreme Temperature Assessment. OR The responsible entity developed and maintained System models for performing Extreme Temperature Assessment, but the System model did not use data consistent with that provided in accordance with the MOD-032 standard supplemented by other sources as needed.
R5.	N/A	N/A	N/A	The responsible entity, as determined in Requirement R1, did not have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for performing Extreme Temperature Assessment.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6.	N/A	N/A	N/A	The responsible entity failed to define and document, the criteria or methodology used in the analysis to identify System instability, uncontrolled separation, or Cascading.
R7.	N/A	N/A	The responsible entity, as determined in Requirement R1, identified Contingencies for performing Extreme Temperature Assessment for each of the event categories in Table 1 that are expected to produce more severe System impacts within its planning area, but did not include the rationale for those Contingencies selected for evaluation as supporting documentation.	The responsible entity, as determined in Requirement R1, did not identify Contingencies for performing Extreme Temperature Assessment for each of the event categories in Table 1 that are expected to produce more severe System impacts within its planning area.
R8.	The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was completed less	The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was completed more than	The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was completed more than	The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was more than 18 months late.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	than or equal to six months late.	six months but less than or equal to 12 months late.	12 months but less than or equal to than 18 months late.	OR The responsible entity, as determined in Requirement R1, did not complete an Extreme Temperature Assessment. OR The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was missing one or more of the required elements in Requirement R8.
R9.	N/A	N/A	The responsible entity, as determined in Requirement R1, developed a CAP, but failed to solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.	The responsible entity, as determined in Requirement R1, failed to develop a Corrective Action Plan when the benchmark planning case study results indicate the System is unable to meet performance requirements for the Table 1 P0 or P1 Contingencies.
R10.	N/A	N/A	N/A	Each responsible entity, as determined in Requirement

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				R1, failed to evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the benchmark planning case study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, P5, and P7 Contingencies.
R11.	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 60 days but less than or equal to 80 days following the request.	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 80 days but less than or equal to 100 days following the request.	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 100 days but less than or equal to 120 days following the request.	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 120 days following the request. OR The responsible entity, as determined in Requirement R1, did not distribute its Extreme Temperature Assessment results to

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				functional entities having a reliability related need who requested the information in writing.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan for 2023-07
- Technical Rationale Document
- Consideration of Issues and Directives for FERC Order 896.

Version History

Version	Date	Action	Change Tracking
1	TBD	Addressing FERC Order 896	New Standard

Implementation Plan

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather

Applicable Standard

- TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events

Requested Retirement

- Not applicable

Prerequisite Standard

- Not applicable

Applicable Entities

- Planning Coordinators
- Transmission Planners

New Terms in the NERC Glossary of Terms

- Extreme Temperature Assessment

Background

On June 15, 2023, FERC issued a Final Rulemaking directing NERC to develop a new or modified Reliability Standard to address the lack of a long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or develop a new Reliability Standard that require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of Corrective Action Plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met.

Effective Date

The effective date for the proposed Reliability Standard is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of the proposed Reliability Standard (e.g., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. These phased-in compliance dates represent the dates that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

TPL-008-1

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 twelve (12) 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 twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Phased-In Compliance Dates

Compliance Date for TPL-008-1 Requirements R1

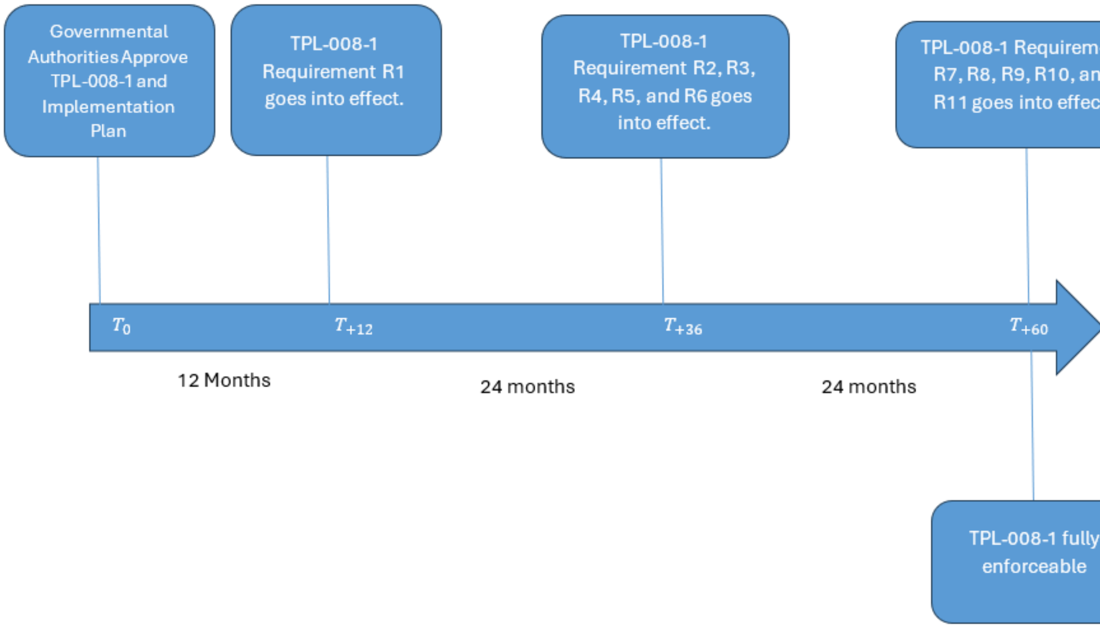
Entities shall be required to comply with Requirements R1 upon the effective date of Reliability Standard TPL-008-1.

Compliance Date for TPL-008-1 Requirements R2, R3, R4, R5, R6

Entities shall not be required to comply with Requirement R2, R3, R4, R5, and R6 until thirty-six (36) months after the effective date of Reliability Standard TPL-008-1.

Compliance Date for TPL-008-1 Requirements R7, R8, R9, R10, R11

Entities shall not be required to comply with Requirement R7, R8, R9, R10, R11 until sixty (60) months after the effective date of Reliability Standard TPL-008-1.


Governmental Authorities Approve TPL-008-1 and Implementation Plan
TPL-008-1 Requirement R1 goes into effect.
TPL-008-1 Requirement R2, R3, R4, R5, and R6 goes into effect.
TPL-008-1 Requirement R7, R8, R9, R10, and R11 goes into effect.
T_0
T_{+12}
T_{+36}
T_{+60}
12 Months
24 months
24 months
TPL-008-1 fully enforceable

NERC Legal and Regulatory Update
February 7, 2024 – March 8, 2024

NERC FILINGS TO FERC SUBMITTED SINCE LAST SC UPDATE

FERC Docket No.	Filing Description	FERC Submittal Date
RD22-4-001	Inverter Based Resources Work Plan Progress Update NERC submitted a progress update on its Inverter Based Resources Work Plan as directed by FERC in its November 17, 2022 Order.	2/12/2024
RD24-5-000	Petition for Approval of Reliability Standard EOP-012-2 and Request for Expedited Action NERC submitted a Petition for Approval of Proposed Reliability Standard EOP-012-2 and Request for Expedited Action.	2/16/2024
RD23-1-002	Compliance Filing for Cold Weather Data Collection NERC submitted a compliance filing for Cold Weather Data Collection as directed by FERC in its February 16, 2023 Order.	2/16/2024
RD20-9-000	BAL-003 Errata Letter NERC submitted an informational filing errata to correct a typographical error in the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard. The procedure was updated in 2019 when NERC revised BAL-003-2 and the error was recently identified. The procedure is on NERC's website, as well as being informationally filed with the Commission.	2/27/2024
RD24-6-000	Petition for approval of Reporting ACE definition and related terms NERC submitted for Commission approval two new, thirty modified, and four retired definitions of terms related to the calculation of Reporting Area Control Error (Reporting ACE), for inclusion in the Glossary of Terms used in NERC Reliability Standards.	3/8/2024

FERC ISSUANCES SINCE LAST SC UPDATE

FERC Docket No.	Issuance Description	FERC Issuance Date
RD24-1-000	Order Approving Reliability Standards EOP-011-4 and TOP-002-5 FERC issued an Order Approving Extreme Cold Weather Reliability Standards EOP-011-4 and TOP-002-5.	2/15/2024

ANTICIPATED UPCOMING FILINGS

FERC Docket No.	Filing Description	Anticipated Filing Date
RD20-2-000	CIP SDT Schedule Update	3/15/2024
TBD	CIP-008 Annual Report	3/21/2024