Agenda
Standards Committee Meeting

September 21, 2022 | 10:00 a.m.—3:00 p.m. Central

Dial-in: 1-415-655-0002 | Access Code: 2317 933 6871 | Meeting Password: 092122
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Introduction and Chair's Remarks

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

Agenda Items

1. **Review September 21, 2022 Agenda - Approve - *Amy Casuscelli* (1 minute)**
2. **Consent Agenda - Approve - *Amy Casuscelli* (5 minutes)**
   a. July 20, 2022 Standards Committee Meeting Minutes* - **Approve**
   b. Project Management and Oversight Subcommittee (PMOS) Leadership* - **Inform**
   c. Standards Committee Process Subcommittee (SCPS) Leadership* - **Inform**
3. **Projects Under Development - Review**
   a. Project Tracking Spreadsheet - *Charles Yeung* (5 minutes)
   b. Three-Month Outlook*- *Latrice Harkness* (5 minutes)
   c. Projected Posting Schedule - *Latrice Harkness* (5 minutes)
4. **Project 2021-03 CIP-002 Transmission Owner Control Center Supplemental Standard Drafting Team Members - Appoint - *Latrice Harkness* (10 minutes)**
5. **Project 2020-02 Modifications to PRC-024 Generator Ride-through Standard Authorization Request Drafting Team Members - Appoint - *Latrice Harkness* (10 minutes)**
6. **Project 2021-02 Modifications to VAR-002-4.1 Supplemental Standard Drafting Team Members -Appoint - *Latrice Harkness* (10 minutes)**
7. **Project 2022-03 Energy Assurance with Energy-Constrained Resources Standard Authorization Request Drafting Team Members - Appoint - *Latrice Harkness* (10 minutes)**
8. **Project 2022-02 Modifications to TPL-001-5.1 and MOD-032-1 - Accept/Authorize/Appoint - *Latrice Harkness* (10 minutes)**
   a. Project 2022-02 MOD-032 SAR*

   b. Project 2020-02 TPL-001-5.1 IRPWG SAR*
   c. Project 2020-02 TPL-001-5.1 SPIDERWG SAR*

9. **CIP-008 Reporting Threshold Standard Authorization Request - Accept/Authorize/Authorize -*Latrice Harkness* (10 minutes)**
   a. CIP-008 Reporting Threshold SAR*

10. **Project 2021-08 Modifications to FAC-008 - Accept/Authorize/Appoint - *Latrice Harkness* (10 minutes)**
    a. FAC-008-5 SAR*

11. **Project 2021-01 Modifications to MOD-025 and PRC-019 - Authorize - *Latrice Harkness* (10 minutes)**
    a. 2021-01 Draft MOD-025-3*
    b. 2021-01 Draft PRC-019-3*
    c. 2021-01 Draft MOD-025-3 Implementation Plan*
    d. 2021-01 Draft PRC-019-3 Implementation plan*

12. **Project 2021-05 Modifications to PRC-023 - Authorize - *Latrice Harkness* (10 minutes)**
    a. 2021-05 Draft PRC-023-6*
    b. 2021-05 Draft Implementation Plan*

13. **2023-2025 Reliability Standards Development Plan - Endorse - *Latrice Harkness* (5 minutes)**
    a. 2023-2025 Reliability Standards Development Plan*

14. **Revisions to the NERC Rules of Procedure Regarding Reliability Standards - Inform - *Lauren Perotti* (5 minutes)**

15. **2023-2024 Term Elections - Inform - *Alison Oswald* (5 minutes)**

16. **Subcommittee Updates**
    a. PMOS – Charles Yeung (10 minutes)
    b. SCPS – Matt Harward (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 – Amy Casuscelli (10 minutes)

17. **Legal Update and Upcoming Standards Filings* - Review - *Lauren Perotti* (5 minutes)**

18. **Informational Items - Enclosed**
    a. Standards Committee Expectations*

b. [2022 SC Meeting Schedule]
c. [2022 Standards Committee Roster]
d. Highlights of Parliamentary Procedure*

19. Adjournment

*Background materials included.

Public Meeting Notice

REMINDER FOR USE AT BEGINNING OF MEETINGS AND CONFERENCE CALLS THAT HAVE BEEN PUBLICLY NOTICED AND ARE OPEN TO THE PUBLIC

Conference call/webinar version:

As a reminder to all participants, this webinar is public. The registration information was posted on the NERC website and widely distributed. Speakers on the call should keep in mind that the listening audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.

Face-to-face meeting version:

As a reminder to all participants, this meeting is public. Notice of the meeting was posted on the NERC website and widely distributed. Participants should keep in mind that the audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.

For face-to-face meeting, with dial-in capability:

As a reminder to all participants, this meeting is public. Notice of the meeting was posted on the NERC website and widely distributed. The notice included the number for dial-in participation. Participants should keep in mind that the audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.

Minutes
Standards Committee Conference Call

July 20, 2022 | 10:00 a.m.—4:00 p.m. Mountain

A. Casuscelli, chair, called to order the meeting of the Standards Committee (SC or the Committee) on July 20, at 10:00 a.m. Mountain. A. Oswald, secretary, called roll and determined the meeting had quorum. The SC member attendance and proxy sheets are attached as Attachment 1.

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

Introduction and Chair's Remarks
A. Casuscelli welcomed the committee, guests, and proxies to the in-person meeting in Denver, CO. She reviewed in-person and WebEx etiquette. She announced that the special election for Segment 9 did not receive any nominations, so the seat will remain vacant. Additionally, she announced there is a change in the SCPS leadership and encouraged the SC members to join the subcommittee to help fill leadership positions going forward. Before starting the meeting, all SC members attending in-person introduced themselves and provided a brief biography.

Review July 20, 2022 Agenda (agenda item 1)
The Committee approved the July 20 meeting agenda.

Consent Agenda (agenda time 2)
The Committee approved the June 15, 2022 SC Meeting Minutes. S. Rueckert abstained.

Projects Under Development (agenda item 3)
C. Yeung reviewed the Project Tracking Spreadsheet. L. Harkness reviewed the Projected Posting Schedule and the Three Month Outlook. She informed the committee that a SAR for CIP-008 might be coming in August.

EMT Models (agenda item 4)
L. Harkness provided an overview. C. Yeung noted that this impact is on generators and asked if there is a way to approach the issue in a more proactive and comprehensive approach. H. Gugel stated an approach is being considered. M. Hostler asked if this SAR will be integrated with the other MOD-032 SAR. H. Gugel responded that when this SAR is posted for industry comment that feedback will be received and considered. J. Howell stated that having models to reflect accurate information would be helpful. H Gugel stated IEEE is aware of the need for industry standards in this area. C. Yeung asked if there is a deadline or priority for this given IEEE might be addressing this issue as well. H. Gugel stated that the drafting team would have the best expertise to determine that. S. Rueckert made a motion to accept the Standard Authorization Request (SAR) that was endorsed by the Reliability and Security Technical Committee

(RSTC) and is recommended by NERC staff; authorize posting of the SAR for a 30-day informal comment period; and authorize solicitation of the SAR drafting team (DT) members.

The committee approved the motion with no objections or abstentions.

Project 2017-01 Modifications to BAL-003-1.1 Frequency Response and Frequency Bias Setting (agenda item 5)

L. Harkness provided an overview. S. Bodkin noted that there is a missing link to the Implementation Plan in the standard. L. Harkness noted that it will be added once the standard is posted for comment and ballot. J. Howell stated that the redline is incorrect on the defined terms section. The entire definitions page should be redlined since the definitions being proposed are new. L. Harkness stated it will be reviewed and corrected before posting. C. Yeung made a motion to authorize initial posting of proposed Reliability Standard BAL-003-3, the associated Implementation Plan, and related revised definitions for a 45-day formal comment period, with ballot pool 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.

The committee approved the motion with no objections or abstentions.

Reliability Standards Development Plan (agenda item 6)

L. Harkness informed the committee that the 2023-2025 Reliability Standards Development Plan (RSDP) will be posted for informal comment in July. The RSDP will be presented to the SC at the September meeting to be endorsed and filed with the NERC Board and FERC by the end of the year.

Subcommittee Updates (agenda item 7)

C. Yeung provided an overview on how standard drafting teams are addressing the SER recommendations. K. Feliks updated the committee on the SCPS leadership change. He will be stepping down as the chair while Matt Harward takes the chair role and L. Oelker becomes the vice chair.

Standing Committees Coordinating Group Report (agenda item 8)

T. Bennett provided an update on the Standing Committees Coordinating Group.

Reliability and Security Technical Committee Report (agenda item 9)

V. Greaff provided an update on the Reliability and Security Technical Committee.

Legal Update and Upcoming Standards Filings (agenda item 10)

L. Perotti provided the legal update regarding recent and upcoming filings. K. Feliks asked if NERC will share comments on the current NOPR. L. Perotti stated that the comments have been shared with the trades.

Adjournment

A. Casuscelli adjourned the meeting at 11:47 a.m. Mountain.

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Standards Committee
2022 Segment Representatives

Segment and Terms	Representative	Organization	Proxy	Present (Member or Proxy)
Chair 2022-23	Amy Casuscelli Manager, Reliability Assurance & Risk Management	Xcel Energy		X
Vice Chair 2022-23	Todd Bennett Managing Director, Reliability Compliance & Audit Services	Associated Electric Cooperative, Inc.		X
Segment 1-2022-23	Michael Jones Manager, Reliability Standards & Policy	National Grid		X
Segment 1-2021-22	Troy Brumfield Regulatory Compliance Manager	American Transmission Company		X
Segment 2-2022-23	Jamie Johnson Compliance Analyst Lead – RC Operations	California ISO	Greg Campoli	X
Segment 2-2021-22	Charles Yeung Executive Director Interregional Affairs	Southwest Power Pool		X
Segment 3-2022-23	Kent Feliks Manager NERC Reliability Assurance – Strategic Initiatives	American Electric Power Company, Inc.		X
Segment 3-2021-22	Linn Oelker Manager – Market Compliance	LG&E and KU Services Company		X
Segment 4-2022-23	Marty Hostler Reliability Compliance Manager	Northern California Power Agency		X
Segment 4-2021-22	Alice Wright Senior Director, Compliance Services	Arkansas Electric Cooperative Corporation		X
Segment 5-2022-23	Terri Pyle Utility Operational Compliance and NERC Compliance Office	Oklahoma Gas and Electric		X
Segment 5-2021-22	Jim Howell Markets Compliance Manager	Southern Company Generation		X

Segment and Terms	Representative	Organization	Proxy	Present (Member or Proxy)
Segment 6-2022-23	Sarah Snow* Manager of Reliability Compliance	Cooperative Energy		X
Segment 6-2021-22	Justin Welty Senior Manager, NERC Reliability Standards	NextEra Energy		X
Segment 7-2022-23	Kristine Martz Industry Specialist, Power & Utilities	Amazon Web Services		X
Segment 7-2021-22	Venona Greaff* Senior Energy Analyst	Occidental Chemical Corporation		X
Segment 8-2022-23	Robert Blohm[1] Managing Director	Keen Resources Ltd.		X
Segment 8-2021-22	Philip Winston* Retired (Southern Company)	Independent		X
Segment 9-2022-23	Sarosh Muncherji Cyber Security Specialist	British Columbia Utilities Commission		X
Segment 9-2021-22	Vacant			
Segment 10-2022-23	Tony Purgar Manager, Operational Analysis & Awareness	ReliabilityFirst		X
Segment 10-2021-22	Steven Rueckert Director of Standards	WECC		X

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

Project Management and Oversight Subcommittee Leadership

Action
Inform

Background
The Project Management and Oversight Subcommittee (PMOS) Officer terms will end December 2022. The PMOS Scope requires "at least one PMOS officer must also be a member of the Standards Committee (SC)." As the only current SC member of the PMOS, Charles Yeung of Southwest Power Pool, will vacate the Chair position and assume the role of Vice Chair. Michael Brytowski of Great River Energy, the current Vice Chair, will assume the role of Chair.

The leadership selections were supported by the PMOS members at the July 19, 2022 meeting. The SC Chair, in accordance with the PMOS Charter, subsequently appointed the Chair and Vice Chair to the PMOS as recommended by subcommittee membership.

Agenda Item 2c
Standards Committee
September 21, 2022

Standards Committee Process Subcommittee Leadership

Action
Inform

Background
The Standards Committee Process Subcommittee (SCPS) chair resigned at the July 20, 2022 SCPS meeting. The Vice Chair, Matt Harward, assumed the chair role. The SCPS Scope requires "at least one SCPS officer must also be a member of the Standards Committee (SC)." Therefore, Linn Oelker assumed the role of vice chair to meet this requirement.

The leadership selections were supported by the SCPS members at the July 20, 2022 meeting. The SC Chair, in accordance with the SCPS Charter, subsequently appointed the Chair and Vice Chair to the SCPS as recommended by subcommittee membership.

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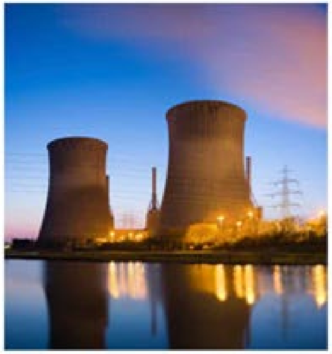
Agenda Item 3b
Standards Committee
September 21, 2022

Three-Month Outlook

Fourth Quarter 2022

Latrice Harkness, Manager of Standards Development, NERC
Standards Committee
September 21, 2022

RELIABILITY | RESILIENCE | SECURITY

Accept/Authorize Standard Authorization Request Postings

- October
  - EOP-004-4 Standard Authorization Request
- November
  - None
- December
  - None

Authorize Nomination Solicitations

- October
  - EOP-004-4 Standard Authorization Request
- November
  - None
- December
  - None

Appoint Drafting Teams

- October
  - None
- November
  - None
- December
  - CIP-008 Reporting Threshold

Authorize Initial Postings

- October
  - 2021-02 Modifications to VAR-002
  - 2021-06 Modifications to IRO-010 and TOP-003
- November
  - 2019-04 Modifications to PRC-005-6
- December
  - None

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Questions and Answers

Project 2021-03 CIP-002 Transmission Owner Control Center

Action

Appoint supplemental standard drafting team (SDT) members to Project 2021-03 CIP-002 Transmission Owner Control Center (TOCC), as recommended by NERC staff.

Background

The Standards Committee (SC) has tasked the Project 2021-03 SDT with three Standard Authorization Requests and one Request for Interpretation (RFI):

1. TOCCs – The SC assigned a portion of the Project 2016-02 SAR that relates to TOCCs to the Project 2021-03 SDT. That SAR portion is to review CIP-002 and evaluate the categorization of TOCCs performing the functional obligations of a Transmission Operator (TOP), specifically those that meet medium impact criteria. In addition, this SDT is assisting NERC staff in meeting the directive from the NERC Board of Trustees to conduct further study of the need to readdress the applicability of the Critical Infrastructure Protection (CIP) Reliability Standards to these Control Centers to support reliability. To help meet this directive and the scope of the SAR, the SDT initiated a field test. The SC approved the Project 2021-03 Field Test Plan on November 17, 2021.
2. CIP-002 and CIP-014 – This SAR provides revisions to CIP-002 and CIP-014 to clarify the responsibility of Reliability Coordinators, Planning Coordinators, and Transmission Planners in identifying Facilities that warrant consideration under these Reliability Standards. As it relates to the Transmission Planner and Planning Coordinator functions, the language "critical to the derivation of Interconnection Reliability Operating Limits (IROLs)" should be replaced/updated to appropriately identify Facilities that, if somehow compromised, could significantly impact the reliability of the Bulk Electric System (BES). Additionally, this SAR includes a review of the applicability of Facilities identified by the Reliability Coordinator as critical to the derivation of IROLs to CIP-002 and CIP-014. The SC accepted this SAR on July 21, 2021.
3. CIP-002 RFI for Requirement R1 Parts 1.1 – 1.3 – This RFI is regarding serial communication devices. The SC accepted the RFI on January 19, 2022 and assigned it to this SDT on February 16, 2022.
4. CIP-002 – This SAR seeks to revise CIP-002 to include identification and categorization of certain Cyber Assets (Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets) associated with high and medium impact BES Cyber Systems. The SC accepted this SAR on November 17, 2021.

The Project 2021-03 SDT originally included nine members, but now the team is down to five SDT members. The three supplemental SDT members would assist project 2021-03 in completing the remaining three SARs assigned to this project.

Summary

From May 23 – June 22, 2022, NERC solicited nominations for supplemental volunteers to serve on a SDT. NERC staff received three nominations from industry professionals and recommends the three individuals, as they have the requisite background, experience, and skills necessary for membership on the SDT.

2020-02 Modifications to PRC-024 (Generator Ride-through)
SAR Drafting Team Recommendation

Action

Appoint supplemental members and vice chair to the Drafting Team (DT) for 2020-02 Modifications to PRC-024 (Generator Ride-through), as recommended by NERC staff.

Background

Project 2020-02 addresses two SARs. The Standards Committee (SC) accepted the first SAR, regarding applicability of transmission-connected dynamic reactive resources, on March 18, 2020. The SC also appointed a SAR Drafting Team (DT) on September 23, 2021. Subsequently, the SC accepted a second SAR on May 18, 2022. On that same date, the SC also assigned the second SAR to Project 2020-02. NERC staff updated the title of the project from "Transmission-connected Dynamic Reactive Resources" to "Modifications to PRC-024 (Generator Ride-Through)" to reflect the addition of the second SAR to the scope of the SAR DT's work.

Specifically, the second SAR seeks to retire PRC-024-3 and replace it with a performance-based ride-through standard that ensures generators remain connected to the Bulk Power System during system disturbances. The SAR focuses on the generator protection and control systems that can result in the reduction or disconnection of generating resources during these events. The SAR also seeks to ensure protection or controls that fail to ride through system events are analyzed, addressed with a corrective action plan (if possible), and reported to necessary entities for situational awareness. From a risk-based perspective, the goal of the standard 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 as well as 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.

To help ensure the appropriate expertise on the SAR DT, NERC solicited nominations from May 31 to July 14, 2022 for additional volunteers to serve on a SAR DT for Modifications to PRC-024 (Generator Ride-through). NERC staff received eight nominations and recommends seven of these candidates as they have the requisite background, experience, and skills necessary for membership on the SAR drafting team. These seven individuals will join the five current team members to have a total of twelve individuals on the team.

Project 2021-02 Modifications to VAR-002-4.1

Action

Appoint the additional candidates for Project 2021-02 Modifications to VAR-002-4.1 to the Project 2021-02 Standard Drafting Team (SDT), as recommended by NERC staff.

Background

Based on its comprehensive review of the NERC Reliability Standards,[1] the NERC Inverter-Based Resource Performance Task Force (IRPTF) developed a Standard Authorization Request (SAR) to revise VAR-002 to address issues regarding whether the Generator Operator of a dispersed power producing resource must notify its associated Transmission Operator upon a status change of a voltage controlling device on an individual generating unit; for example, if a single inverter goes offline in a solar photo-voltaic Facility.

The SAR was endorsed by the Reliability and Security Technical Committee on June 10, 2020 and was accepted and authorized for informal comment posting by the Standards Committee (SC) on January 20, 2021. On July 21, 2021 the SC appointed the chair, vice chair, and members to the Project 2021-02 Modifications to VAR-002-4.1 SAR Drafting Team (DT). The SAR was posted for industry comments April 14, 2021 – May 13, 2021 and March 7, 2022 – April 6, 2022.

On June 15, 2022 the SC (1) accepted the revised Project 2021-02 Modifications to VAR-002-4.1 SAR; (2) authorized drafting revisions to the Reliability Standard identified in the SAR; (3) appointed the Project 2021-02 SAR DT as the Project 2021-02 SDT; and (4) authorized a 30-day solicitation for nominations period for the Project 2021-02 Modifications to VAR-002-4.1 SDT to add additional members to the SDT with specific industry expertise as Transmission Operators who receive and apply information to its respective Real-time assessment and Real-Time monitoring activities.

From June 16 through July 15, 2022, NERC solicited supplemental nominations for volunteers to serve on the Project 2021-02 Modifications to VAR-002-4.1 SDT. Of these nominations, NERC staff recommends that three be appointed, as they will provide the specific industry expertise sought.

Adding SDT member(s) would be consistent with Section 4.3 of the Standard Processes Manual, which states: "The Standards Committee may supplement the membership of a Reliability Standard drafting team or provide for additional advisors, as appropriate, to ensure the necessary competencies and diversity of views are maintained throughout the Reliability Standard development effort."

[1] The review resulted in a whitepaper that included findings and recommendations. IRPTF Review of NERC Reliability Standards White Paper, March 2020, approved by the Operating Committee and the Planning Committee in March 2020, https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf

Project 2022-03 Energy Assurance with Energy-Constrained Resources

Action

Appoint chair, vice chair, and members to the Project 2022-03 Energy Assurance with Energy-Constrained Resources Standard Authorization Request (SAR) drafting team (DT), as recommended by NERC staff.

Background

The Standards Committee (SC) accepted two (2) SARs that were submitted by the Energy Reliability Assessment Task Force (ERATF) at its June 15, 2022 meeting. Both SARs propose to enhance reliability by requiring entities to perform energy reliability assessments to evaluate energy assurance and develop Corrective Action Plan(s) to address identified risks to each respective time horizon:

- Operations/operational planning time horizon (Operations SAR)
- Planning time horizon (Planning SAR).

At the same meeting, the SC authorized soliciting for members for the SAR DT. The informal comment period and the solicitation for the SAR Drafting Team member period ran from June 22, 2022 – July 21, 2022.

NERC received twenty (20) nominations from industry with one (1) withdrawal. NERC staff recommends fourteen (14) individuals with the requisite background, experience, and skills necessary for membership on the SAR DT.

Project 2022-02 Modifications to TPL-001-5.1 and MOD-032-1

Action

- Accept the Project 2022-02 Modifications to TPL-001 and MOD-032 Standard Authorization Requests (SARs);
- Authorize drafting revisions to the Reliability Standards identified in the SARs; and
- Appoint the Project 2022-02 SARs Drafting Team (DT) as the Project 2022-02 Standard Drafting Team (SDT).

Background

Project 2022-02 addresses three SARs submitted by NERC System Planning Impacts from Distributed Energy Resources (DERs) Working Group (SPIDERWG) and NERC Inverter-Based Resource Performance Working Group (IRPWG) to modify Standards TPL-001 and MOD-032 to address gaps in data collection; provide clarity and consistency for how Bulk Power System-connected inverter-based resources are considered, modeled, and studied in planning assessments; and provide clarity or, in some cases, expand the scope of requirements when considering the performance of DERs to ensure the accuracy of Transmission System Planning Assessments.

At the Standards Committee (SC) January 19, 2022 meeting, the SC accepted the SARs and authorized soliciting for members for the SARs DT. The informal comment period for the SARs and the solicitation for the SAR DT members took place from February 1, 2022 to March 2, 2022. At the SC April 20, 2022 meeting, the SC appointed chair, vice chair, and members to the SARs DT.

The SARs DT met six times (including the Project kickoff meeting) from May 11, 2022 through June 22, 2022 to review and make revisions to the SARs. The team considered industry comments during this process.

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	MOD-032-1 Data for Power System Modeling and Analysis		
Date Submitted:	12/15/2021 (Revised on June 22, 2022)		
SAR Requester			
Name:	Kun Zhu (NERC SPIDERWG Chair) Bill Quaintance (NERC SPIDERWG Vice Chair) (Revised by Project 2022-02 SAR Drafting Team)		
Organization:	Kun Zhu – MISO Bill Quaintance – Duke Energy Progress		
Telephone:	Kun – 317-249-5789 Bill – 919-546-4810	Email:	kzhu@misoenergy.org william.quaintance@duke-energy.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☒ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
As the penetration of distributed energy resources (DERs) continues to increase across many distribution systems connected both directly and indirectly to the BES, it is necessary to account for the potential impacts of DERs on reliability in the planning, operation, and design of the BES. The NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) has identified the need for improved modeling of aggregate DER for planning studies (including both utility-scale and retail-scale DER) conducted by Transmission Planners (TPs) and Planning Coordinators (PCs). MOD-032-1 addresses the gathering of modeling data to perform planning assessments but the standard currently has no specific reference to DER data. This SAR proposes to update MOD-032-1 to: (1) include "data			

Requested information
requirements and reporting procedures"[1] for DER that are necessary to support the development of accurate interconnection-wide models, (2) replace Load-Serving Entity (LSE) with Distribution Provider (DP) because of the removal of LSEs from the NERC registry criteria, (3) enable the SDT to review any additional gaps in DER data collection with the de-registration of LSE.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This SAR proposes to revise MOD-032-1 to address gaps in data collection for the purposes of modeling aggregate levels of DERs in planning assessments. The goal is to provide clarity and consistency for data collection across PCs and TPs when coordinating with the DP to gather aggregate load and aggregate DER data.
Project Scope (Define the parameters of the proposed project):
The proposed scope of this project is as follows: a. The table in Attachment 1 should be updated to include DER in the steady-state and dynamics columns. Details of the changes to be considered by the Standard Drafting Team are included in the "Detailed Description" below. Revision to requirements should also be considered if necessary. b. Based on item a.) and the detailed description below, the SDT should consider whether including a definition for "Distributed Energy Resource (DER)" in the NERC Glossary of Terms is necessary. c. In alignment with the SAR submitted by the previous NERC Essential Reliability Services Working Group (ERSWG), LSE should be removed and replaced by DP as the applicable entity in Section 4.1.3 and all instances in the standard requirements and attachments. d. The SDT should review any potential gaps regarding the de-registration of LSE or based on applicability transfer from LSE to DP (item c in this list), including but not limited to data collection for aggregate DER data. e. Consider modification to the applicability section of the standard that would remove the reference to the Planning Authority and align the applicable entities with the NERC functional model of Planning Coordinator.

[1] See Requirement R1 of MOD-032-1, which requires each TP and PC to develop data requirements and reporting procedures for the collection of modeling data used for the development of models for each PC footprint.

Requested information
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[2] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (e.g., research paper) to guide development of the Standard or definition):
This SAR proposes to address the issues identified in the project scope above. Specifically, the following details should be considered and addressed by the drafting team: • In the Applicability section of MOD-032-1, LSE should be replaced with DP, in alignment with the SAR previously submitted by ERSWG. Similarly, all relevant uses of LSE should be replaced with DP.   ▪ The table in Attachment 1 should include references to aggregate DER in the steady-state and dynamics columns. The drafting team should consider the data needed for modeling aggregate DER for the purposes of reliability studies. In particular, the drafting team should consider the recommendations set forth in *NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies*. • Note that the SPIDERWG does not see a need to modify the short circuit column of Attachment 1 because #1 already states "all applicable elements" in the steady-state column should have necessary information related to positive, negative, and zero sequence data provided accordingly. If the TP/PC determines that aggregate DER is needed for these studies, then they have the capability to request such data. However, this is not a prevalent issue currently. • In alignment with adding "DER" to the Attachment 1 table regarding necessary data for modeling purposes, it may be needed (based on the discretion of the SDT) to add a definition for "Distributed Energy Resource (DER)" to the NERC Glossary of Terms. As stated, SPIDERWG has published *NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies* that includes recommended practices and for the collection of aggregate DER data for transmission planning studies. **These materials are not intended to dilute the criticality of this SAR to address the issues identified above within MOD-032-1 itself. Rather, the SDT can use these materials when determining the specific language for inclusion in the standard requirements revisions.**
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Cost impacts are not fully known.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):

[2] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
DER owners are not subject to NERC Reliability Standards. However, SPIDERWG believes the DP (a NERC Registered Entity) has the information regarding DER connected to its distribution system that is needed for modeling the aggregate behavior of DER for the purposes of BES reliability planning studies. The DP should provide that information to the TP and PC accordingly.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g*. Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Transmission Planner, Planning Coordinator, Distribution Provider While not a Functional Entity per the NERC Functional Model, the "MOD-032 Designees" that are designated by the ERO to develop interconnection-wide base cases (i.e., the Regional Entities), will also be affected by these changes and should be considered for appointment to the Standard Drafting Team.
Do you know of any consensus building activities[3] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The proposals in this SAR were developed by the NERC SPIDERWG, a stakeholder group under the NERC Planning Committee.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
The ERSWG submitted a SAR related to MOD-032-1, as described above. This SAR supports those changes, and further expands on a few necessary additional changes related to DER modeling.
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
The NERC SPIDERWG is preparing a Reliability Guideline on data collection for DER modeling. That guideline will provide recommendations for improvements to the data requirements and reporting procedures developed jointly by PCs and their TPs. However, updates to MOD-032-1 are also needed to ensure minimum planning consideration and reporting requirement on DER, particularly in Attachment 1. Therefore, this SAR aligns with the necessary changes to meet the objective.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

[3] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	None

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SAR Status Tracking (Check off as appropriate)	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC

	☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	MOD-032-1 Data for Power System Modeling and Analysis		
Date Submitted:	12/15/2021 (Revised on June 22, 2022)		
SAR Requester			
Name:	Kun Zhu (NERC SPIDERWG Chair) Bill Quaintance (NERC SPIDERWG Vice Chair) (Revised by Project 2022-02 SAR Drafting Team)		
Organization:	Kun Zhu – MISO Bill Quaintance – Duke Energy Progress		
Telephone:	Kun – 317-249-5789 Bill – 919-546-4810	Email:	kzhu@misoenergy.org william.quaintance@duke-energy.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☒ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
As the penetration of distributed energy resources (DERs) continues to increase across ~~the~~ many distribution systems connected both directly and indirectly to the BES~~North American bulk power system (BPS)~~, it is necessary to account for the potential impacts of DERs on reliability in the planning, operation, and design of the BES. The NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) has identified the need for improved modeling of aggregate DER for planning studies (including both utility-scale and retail-scale DER) conducted by Transmission Planners (TPs) and Planning Coordinators (PCs). MOD-032-1 addresses the gathering of modeling data to perform planning assessments but the standard currently has no specific reference to DER data. This SAR proposes to			

Requested information
update MOD-032-1 to: (1) include "data requirements and reporting procedures"[1] for DER that are necessary to support the development of accurate interconnection-wide models, (2) replace Load-Serving Entity (LSE) with Distribution Provider (DP) because of the removal of LSEs from the NERC registry criteria, (3) enable the SDT to review any additional gaps in DER data collection with the de-registration of LSE.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This SAR proposes to revise MOD-032-1 to address gaps in data collection for the purposes of modeling aggregate levels of DERs in planning assessments. The goal is to provide clarity and consistency for data collection across PCs and TPs when coordinating with the DP to gather aggregate load and aggregate DER data.
Project Scope (Define the parameters of the proposed project):
The proposed scope of this project is as follows: a. The table in Attachment 1 should be updated to include DER in the steady-state and dynamics columns. Details of the changes to be considered by the Standard Drafting Team are included in the "Detailed Description" below. Revision to requirements should also be considered if necessary. b. Based on item a.) and the detailed description below, the SDT should consider whether including a definition for "Distributed Energy Resource (DER)" in the NERC Glossary of Terms is necessary. c. In alignment with the SAR submitted by the previous NERC Essential Reliability Services Working Group (ERSWG), LSE should be removed and replaced by DP as the applicable entity in Section 4.1.3 and all instances in the standard requirements and attachments. d. The SDT should review any potential gaps regarding ~~data collection for aggregate DER data with~~ the de-registration of LSE or based on applicability transfer from LSE to DP (item c in this list), including but not limited to data collection for aggregate DER data. ~~d.~~e. Consider modification to the applicability section of the standard that would remove the reference to the Planning Authority and align the applicable entities with the NERC functional model of Planning Coordinator.

[1] See Requirement R1 of MOD-032-1, which requires each TP and PC to develop data requirements and reporting procedures for the collection of modeling data used for the development of models for each PC footprint.

Requested information
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[2] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (e.g., research paper) to guide development of the Standard or definition):
This SAR proposes to address the issues identified in the project scope above. Specifically, the following details should be considered and addressed by the drafting team: • In the Applicability section of MOD-032-1, LSE should be replaced with DP, in alignment with the SAR previously submitted by ERSWG. Similarly, all relevant uses of LSE should be replaced with DP. ▪ The table in Attachment 1 should include references to aggregate DER in the steady-state and dynamics columns. The drafting team should consider the data needed for modeling aggregate DER for the purposes of reliability studies. In particular, the drafting team should consider the recommendations set forth in *NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies*. • Note that the SPIDERWG does not see a need to modify the short circuit column of Attachment 1 because #1 already states "all applicable elements" in the steady-state column should have necessary information related to positive, negative, and zero sequence data provided accordingly. If the TP/PC determines that aggregate DER is needed for these studies, then they have the capability to request such data. However, this is not a prevalent issue currently. • In alignment with adding "DER" to the Attachment 1 table regarding necessary data for modeling purposes, it may be needed (based on the discretion of the SDT) to add a definition for "Distributed Energy Resource (DER)" to the NERC Glossary of Terms. As stated, SPIDERWG has published *NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies* that includes recommended practices and for the collection of aggregate DER data for transmission planning studies. **These materials are not intended to dilute the criticality of this SAR to address the issues identified above within MOD-032-1 itself. Rather, the SDT can use these materials when determining the specific language for inclusion in the standard requirements revisions.**
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Cost impacts are not fully known. ~~However, due to the limited scope of the requested data, cost impact is expected to be minimal to all entities. DPs typically collect the information need to model aggregate levels of DERs in planning assessments. Therefore, data collection effort by the DP would be minimal additional effort. DPs already have processes to provide load data to the TP and PC, so DER data can be~~

[2] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
~~managed in a similar manner to reduce cost and effort. If the scope of the required data is expanded, cost impact would likely increase.~~
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
DER owners are not subject to NERC Reliability Standards. However, SPIDERWG believes the DP (a NERC Registered Entity) has the information regarding DER connected to its distribution system that is needed for modeling the aggregate behavior of DER for the purposes of BES reliability planning studies. The DP should provide that information to the TP and PC accordingly.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g*. Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Transmission Planner, Planning Coordinator, Distribution Provider While not a Functional Entity per the NERC Functional Model, the “MOD-032 Designees” that are designated by the ERO to develop interconnection-wide base cases (i.e., the Regional Entities), will also be affected by these changes and should be considered for appointment to the Standard Drafting Team.
Do you know of any consensus building activities[3] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The proposals in this SAR were developed by the NERC SPIDERWG, a stakeholder group under the NERC Planning Committee.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
The ERSWG submitted a SAR related to MOD-032-1, as described above. This SAR supports those changes, and further expands on a few necessary additional changes related to DER modeling.
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
The NERC SPIDERWG is preparing a Reliability Guideline on data collection for DER modeling. That guideline will provide recommendations for improvements to the data requirements and reporting procedures developed jointly by PCs and their TPs. However, updates to MOD-032-1 are also needed to ensure minimum planning consideration and reporting requirement on DER, particularly in Attachment 1. Therefore, this SAR aligns with the necessary changes to meet the objective.

[3] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	None

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SAR Status Tracking (Check off as appropriate)	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	TPL-001-5.1 Transmission System Planning Performance Requirements		
Date Submitted:	12/16/2021 (Revised on June 22, 2022)		
SAR Requester			
Name:	Allen Schriver, NextEra Energy (NERC IRPWG Chair) Julia Matevosyan, ERCOT (NERC IRPWG Vice Chair) (Revised by Project 2022-02 SAR Drafting Team)		
Organization:	NERC Inverter-Based Resource Performance Working Group (IRPWG)		
Telephone:	Al – 561-904-3234 Julia – 512-994-7914	Email:	Allen.Schriver@fpl.com Julia.Matevosyan@ercot.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☒ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
Many areas of the North American bulk power system (BPS) continue to experience an increase in BPS-connected inverter-based resources (e.g., wind, solar photovoltaic (PV), battery energy storage systems (BESS), and hybrid power plants). NERC Reliability Standard TPL-001-5.1 is a foundational standard used for “establishing transmission system performance requirements within the planning horizon to develop a bulk electric system (BES) that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.” Transmission Planners (TPs) and Planning Coordinators (PCs) develop and use models of the electrical grid to perform planning assessments (e.g., steady-state, dynamic, and short-circuit) to develop corrective action plans for future reliability issues identified. Ensuring that the TPL-001 standard is reflective of the evolving nature of the BPS and its resource mix is paramount to ensuring reliable operation and resilience of the BPS moving forward.			

Requested information
The NERC Inverter-Based Resource Performance Task Force (IRPTF)[1] undertook a complete review of the NERC Reliability Standards in the context of increasing levels of BPS-connected inverter-based resources and published a white paper on the outcomes and recommendations of this review in March 2020.[2] The review was approved by the NERC Planning Committee and served as the technical justification for future standards revision efforts. The white paper recommended modifications to seven standards, and IRPWG presented four SARs to the NERC Reliability and Security Technical Committee (RSTC) in June 2020 that addressed the deficiencies identified in six of the seven standards. Based on the outcome of the review, it was determined that the TPL-001-4/5[3] needed clarifications "to address terminology throughout the standard that is unclear with regards to inverter-based resources" the next time the standard is revised. The language used in the white paper regarding "the next time the standard is revised" was based on the understanding that the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) was developing a SAR and that the recommended modifications to TPL-001-5 from IRPWG could be included in the SPIDERWG SAR. The combined SAR was presented to the NERC RSTC at their March 2021 meeting and was rejected. The overarching comments received were with regards to the DER-related issues and a comment was made that the recommendations pertaining to BPS-connected inverter-based resources were not the primary focus of concern. Therefore, IRPWG presents this SAR to move the effort forward regarding specifically BPS-connected inverter-based resources. This SAR does not include any modification to TPL-001-5 regarding the inclusion of distributed energy resources (DERs). IRPWG believes that industry needs to be proactive in addressing standards gaps, particularly, where lack of clarity and confusion may lead to studies not adequately capturing possible BPS reliability issues. As the North American BPS continues to experience rising penetration levels of BPS-connected inverter-based resources and is likely to do so into the foreseeable future, these changes are critical for overall BPS reliability and industry efforts to reliably integrate these resources.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This SAR revises requirements within the TPL-001-5 standard to provide clarity and consistency for how BPS-connected inverter-based resources are considered, modeled, and studied in planning assessments. The proposed revisions to TPL-001-5 will ensure industry is effectively and efficiently conducting planning assessments and that the requirements are equally suitable for inverter-based resources as they are for synchronous generation.

[1] The IRPTF has subsequently become the IRPWG under the NERC Reliability and Security Technical Committee (RSTC).
[2] NERC IRPTF, "IRPTF Review of NERC Reliability Standards," March 2020: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf
[3] At the time of review, the TPL-001-5 standard had just recently been approved by FERC and was yet to be subject to enforcement.

Requested information
Project Scope (Define the parameters of the proposed project):
As described in further detail below, the scope of this project includes consideration of the following revisions to TPL-001-5.1: • Modify Requirements 3.3 and 4.3 and their applicable sub-requirements to make the term “GSU transformer” suitable for all generation types since it introduces confusion for BPS-connected inverter-based resources • Modify Requirements 4.1.1 and 4.1.2 regarding the use of the term “pulls out of synchronism,” which is only applicable for synchronous generator technologies and is not suitable for BPS-connected inverter-based resources • Modify Requirement 4.3.2 so that the list of devices that impact the study area are inclusive of BPS-connected inverter-based resource technologies •
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[4] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The following detailed description is copied verbatim from the IRPTF white paper that was approved by the NERC PC: TPL-001-4 requires Planning Coordinators (PCs) and TPs to assess the reliability of their portion of the BES for various conditions across several specified future years and to plan Corrective Action Plans to address identified performance deficiencies. The requirements and sub-requirements include, among other things, certain simulation assumptions to be used by the planner and performance requirements. Sub-requirements 3.3 and 4.3 describe simulation assumptions that the planner should use when performing contingency analysis for the steady-state and stability portion of the assessment, respectively. Sub-requirements 3.3.1.1 and 4.3.1.2 each require the planner to include the impact of the “tripping of generators where simulations show generator bus voltages or high side of the [GSU] voltages are less than known or assumed generator” low voltage ride-through capability. The term GSU transformer can be confusing to GOs of IBR facilities because they will often refer to the transformer that steps the voltage up from the individual inverter (e.g., 600 V) to the collector system voltage (e.g., 34.5 kV). In this case, there is usually another transformer (i.e., the main power transformer (MPT)) to step the voltage up from the collector system voltage to transmission system voltage. It was likely the intent of the TPL-001-2 SDT to be referring to transmission system voltages when drafting the language that refers to known or assumed

[4] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
generator low voltage ride-through capability at the high-side of the GSU. Therefore, the language in these sub-requirements should be modified to provide clarity for inverter-based resources. Sub-requirements 4.1.1 and 4.1.2 provide stability performance criteria when a generator "pulls out of synchronism" in system simulations. Although an inverter-based resource does synchronize with the grid, the phrase "pulls out of synchronism" is typically applicable only to synchronous generators, referring to when a synchronous machine has an angular separation from the rest of the grid. Therefore, these sub-requirements could be clarified by clearly stating that this performance criteria is for synchronous generators. Sub-requirement 4.3.2 specifies that stability studies must "simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area." It then contains a list of example devices that have dynamic behavior. Not included in this list are power plant controllers and inverter controls, which often dominate the dynamic response of IBRs. While the sub-requirement does not preclude the simulation of plant-level controllers and inverter controls, it would add clarity if they were added to the list. The suggested clarifications for sub-requirements 3.3, 4.3, 4.1.1, 4.1.2, and 4.3.2 should be considered by a future SDT when editing the standard. However, the IRPTF does not believe the clarifications by themselves warrant changing the standard at this time. It should be noted that the identified issues with TPL-001-4 also apply to the draft TPL-001-5 standard that is awaiting FERC approval as of the publication of this whitepaper.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The cost impacts for the proposed changes to TPL-001-5 are expected to be minimal. The changes being proposed are clarifications that will bring consistency and effectiveness industry related to how planning assessments are conducted and how planning engineers set up and conduct those assessments.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None. This SAR will impact Transmission System Planning Assessments, not any specific BES facilities.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Planning Coordinators, Transmission Planners, and Generator Owners of inverter-based resources

Requested information
Do you know of any consensus building activities[5] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This SAR is an outcome of the white paper produced by the NERC IRPTF and approved by the NERC PC, which can be found here: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf The SAR is a follow-on to the recommendation contained within the white paper, developed by the NERC IRPWG under the NERC RSTC.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
No
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
The NERC IRPWG (previously IRPTF) has published multiple technical reference documents, white papers, and reliability guidelines related to the performance, modeling, and studies of BPS-connected inverter-based resources. These technical materials are used widely by industry and have provided significant value for improving planning practices. However, those efforts do not address the larger issue related to the TPL-001 standards language being written predominantly for synchronous generation technology and not adequately considering or clarifying how the requirements relate to BPS-connected inverter-based resource technologies.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.

[5] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Requested information	
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	None

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

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1	June 3, 2013		Revised

1	August 29, 2014	Standards Information Staff	Updated template
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Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	TPL-001-5.1 Transmission System Planning Performance Requirements		
Date Submitted:	12/16/2021 (Revised on June 22, 2022)		
SAR Requester			
Name:	Allen Schriver, NextEra Energy (NERC IRPWG Chair) Julia Matevosyan, ERCOT (NERC IRPWG Vice Chair) (Revised by Project 2022-02 SAR Drafting Team)		
Organization:	NERC Inverter-Based Resource Performance Working Group (IRPWG)		
Telephone:	Al – 561-904-3234 Julia – 512-994-7914	Email:	Allen.Schriver@fpl.com Julia.Matevosyan@ercot.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☒ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
Many areas of the North American bulk power system (BPS) continue to experience an increase in BPS-connected inverter-based resources (e.g., wind, solar photovoltaic (PV), battery energy storage systems (BESS), and hybrid power plants). NERC Reliability Standard TPL-001-5.1 is a foundational standard used for "establishing transmission system performance requirements within the planning horizon to develop a bulk electric system (BES) that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies." Transmission Planners (TPs) and Planning Coordinators (PCs) develop and use models of the electrical grid to perform planning assessments (e.g., steady-state, dynamic, and short-circuit) to develop corrective action plans for future reliability issues identified. Ensuring that the TPL-001 standard is reflective of the evolving nature of the BPS and its resource mix is paramount to ensuring reliable operation and resilience of the BPS moving forward.			

Requested information
The NERC Inverter-Based Resource Performance Task Force (IRPTF)[1] undertook a complete review of the NERC Reliability Standards in the context of increasing levels of BPS-connected inverter-based resources and published a white paper on the outcomes and recommendations of this review in March 2020.[2] The review was approved by the NERC Planning Committee and served as the technical justification for future standards revision efforts. The white paper recommended modifications to seven standards, and IRPWG presented four SARs to the NERC Reliability and Security Technical Committee (RSTC) in June 2020 that addressed the deficiencies identified in six of the seven standards. Based on the outcome of the review, it was determined that the TPL-001-4/5[3] needed clarifications "to address terminology throughout the standard that is unclear with regards to inverter-based resources" the next time the standard is revised. The language used in the white paper regarding "the next time the standard is revised" was based on the understanding that the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) was developing a SAR and that the recommended modifications to TPL-001-5 from IRPWG could be included in the SPIDERWG SAR. The combined SAR was presented to the NERC RSTC at their March 2021 meeting and was rejected. The overarching comments received were with regards to the DER-related issues and a comment was made that the recommendations pertaining to BPS-connected inverter-based resources were not the primary focus of concern. Therefore, IRPWG presents this SAR to move the effort forward regarding specifically BPS-connected inverter-based resources. This SAR does not include any modification to TPL-001-5 regarding the inclusion of distributed energy resources (DERs). IRPWG believes that industry needs to be proactive in addressing standards gaps, particularly, where lack of clarity and confusion may lead to studies not adequately capturing possible BPS reliability issues. As the North American BPS continues to experience rising penetration levels of BPS-connected inverter-based resources and is likely to do so into the foreseeable future, these changes are critical for overall BPS reliability and industry efforts to reliably integrate these resources.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This SAR revises requirements within the TPL-001-5 standard to provide clarity and consistency for how BPS-connected inverter-based resources are considered, modeled, and studied in planning assessments. The proposed revisions to TPL-001-5 will ensure industry is effectively and efficiently conducting planning assessments and that the requirements are equally suitable for inverter-based resources as they are for synchronous generation.

[1] The IRPTF has subsequently become the IRPWG under the NERC Reliability and Security Technical Committee (RSTC).
[2] NERC IRPTF, "IRPTF Review of NERC Reliability Standards," March 2020: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf
[3] At the time of review, the TPL-001-5 standard had just recently been approved by FERC and was yet to be subject to enforcement.

Requested information
Project Scope (Define the parameters of the proposed project):
As described in further detail below, the scope of this project includes consideration of the following revisions to TPL-001-5.1: • Modify Requirements 3.3 and 4.3 and their applicable sub-requirements to make the term "GSU transformer" suitable for all generation types since it introduces confusion for BPS-connected inverter-based resources • Modify Requirements 4.1.1 and 4.1.2 regarding the use of the term "pulls out of synchronism," which is only applicable for synchronous generator technologies and is not suitable for BPS-connected inverter-based resources • Modify Requirement 4.3.2 so that the list of devices that impact the study area are inclusive of BPS-connected inverter-based resource technologies •
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[4] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The following detailed description is copied verbatim from the IRPTF white paper that was approved by the NERC PC: TPL-001-4 requires Planning Coordinators (PCs) and TPs to assess the reliability of their portion of the BES for various conditions across several specified future years and to plan Corrective Action Plans to address identified performance deficiencies. The requirements and sub-requirements include, among other things, certain simulation assumptions to be used by the planner and performance requirements. Sub-requirements 3.3 and 4.3 describe simulation assumptions that the planner should use when performing contingency analysis for the steady-state and stability portion of the assessment, respectively. Sub-requirements 3.3.1.1 and 4.3.1.2 each require the planner to include the impact of the "tripping of generators where simulations show generator bus voltages or high side of the [GSU] voltages are less than known or assumed generator" low voltage ride-through capability. The term GSU transformer can be confusing to GOs of IBR facilities because they will often refer to the transformer that steps the voltage up from the individual inverter (e.g., 600 V) to the collector system voltage (e.g., 34.5 kV). In this case, there is usually another transformer (i.e., the main power transformer (MPT)) to step the voltage up from the collector system voltage to transmission system voltage. It was likely the intent of the TPL-001-2 SDT to be referring to transmission system voltages when drafting the language that refers to known or assumed

[4] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
generator low voltage ride-through capability at the high-side of the GSU. Therefore, the language in these sub-requirements should be modified to provide clarity for inverter-based resources. Sub-requirements 4.1.1 and 4.1.2 provide stability performance criteria when a generator "pulls out of synchronism" in system simulations. Although an inverter-based resource does synchronize with the grid, the phrase "pulls out of synchronism" is typically applicable only to synchronous generators, referring to when a synchronous machine has an angular separation from the rest of the grid. Therefore, these sub-requirements could be clarified by clearly stating that this performance criteria is for synchronous generators. Sub-requirement 4.3.2 specifies that stability studies must "simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area." It then contains a list of example devices that have dynamic behavior. Not included in this list are power plant controllers and inverter controls, which often dominate the dynamic response of IBRs. While the sub-requirement does not preclude the simulation of plant-level controllers and inverter controls, it would add clarity if they were added to the list. The suggested clarifications for sub-requirements 3.3, 4.3, 4.1.1, 4.1.2, and 4.3.2 should be considered by a future SDT when editing the standard. However, the IRPTF does not believe the clarifications by themselves warrant changing the standard at this time. It should be noted that the identified issues with TPL-001-4 also apply to the draft TPL-001-5 standard that is awaiting FERC approval as of the publication of this whitepaper.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The cost impacts for the proposed changes to TPL-001-5 are expected to be minimal. The changes being proposed are clarifications that will bring consistency and effectiveness industry related to how planning assessments are conducted and how planning engineers set up and conduct those assessments.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None. This SAR will impact Transmission System Planning Assessments, not any specific BES facilities.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Planning Coordinators, Transmission Planners, and Generator Owners of inverter-based resources

Requested information
Do you know of any consensus building activities[5] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This SAR is an outcome of the white paper produced by the NERC IRPTF and approved by the NERC PC, which can be found here: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf The SAR is a follow-on to the recommendation contained within the white paper, developed by the NERC IRPWG under the NERC RSTC.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
No
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
The NERC IRPWG (previously IRPTF) has published multiple technical reference documents, white papers, and reliability guidelines related to the performance, modeling, and studies of BPS-connected inverter-based resources. These technical materials are used widely by industry and have provided significant value for improving planning practices. However, those efforts do not address the larger issue related to the TPL-001 standards language being written predominantly for synchronous generation technology and not adequately considering or clarifying how the requirements relate to BPS-connected inverter-based resource technologies.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.

[5] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Requested information	
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	None

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SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

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The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	TPL-001-5.1 Transmission System Planning Performance Requirements		
Date Submitted:	12/15/2021 (Revised on June 22, 2022)		
SAR Requester			
Name:	Kun Zhu, MISO (NERC SPIDERWG Chair) Bill Quaintance, Duke Energy Progress (NERC SPIDERWG Vice-Chair) (Revised by Project 2022-02 SAR Drafting Team)		
Organization:	NERC System Planning Impacts from DERs Working Group (SPIDERWG)		
Telephone:	Kun – 317-249-5789 Bill – 919-546-4810	Email:	kzhu@misoenergy.org william.quaintance@duke-energy.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☒ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☒ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
Many distribution systems connected both directly and indirectly to the North American BES are experiencing increasing penetrations of distributed energy resources (DERs). NERC Reliability Standard TPL-001-5.1[1] was developed under a paradigm of predominantly BPS-connected generation, particularly synchronous generation, when penetrations of DERs were significantly lower than current and future projections. Considering current trends, the NERC SPIDERWG undertook a review of the TPL-001 standard considering the potential impact of DERs. This review is captured in the following RSTC-approved white paper and serves as the technical justification for the revisions suggested in this SAR:			

[1] The scope of recent modifications to TPL-001-5 did not include considering the impacts of DER on BES planning.

Requested information
• SPIDERWG: Assessment of DER impacts on NERC Reliability Standard TPL-001 (here) This SAR proposes to update TPL-001-5.1 to address some of the issues identified in the white paper. TPL-001-5.1 does not currently require Planning Coordinators and Transmission Planners to complete Planning Assessments with adequate representation of the dynamic behavior of DERs. As the penetration of DERs increases, and based on the DER data and models available, Planning Assessments should include DERs that can potentially impact Transmission System performance assessment. NERC's "Lesson Learned: Single Phase Fault Precipitates Loss of Generation and Load", evaluating a 2019 frequency event in Southern England exacerbated by the unexpected reduction of 725 MW of IBR output and the unexpected loss of 350 MW of DER, highlights the critical importance of accurate Transmission System Planning Assessments.[2] In July 2020, a significant quantity of solar PV facilities across a large geographic area in Southern CA reduced about 1000 MW output due to a disturbance on the bulk power system[3]. Subsequent event analysis revealed that it was the consequence of momentary cessation and slow recovery of power. Standards enhancement has been one of the recommendations after the event analysis to ensure reliable operation of the bulk power system. In general, the impact of DERs on the BES should be included in planning assessments if DER data and models are available. Any choice to exclude the consideration of the impact of DER on the BES should be supported by a technical rationale and/or justification.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The purpose of this SAR is to revise requirements to provide clarity or, in some cases, expand the scope of requirements when considering the performance of DERs to ensure the accuracy of Transmission System Planning Assessments.
Project Scope (Define the parameters of the proposed project):
As identified by SPIDERWG, revision to the following sections of TPL-001-5.1 should be considered to ensure the accuracy of Transmission System Planning Assessments: a. R2.1, R2.2, and R2.4, the use of phrase "System peak Load" b. R3.3.1.1 and R4.3.1.2, the "tripping of generators" in steady state and stability contingency analysis should include tripping of DER if data and models are available. The SDT can consider whether a threshold needs to be established.

2 https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20201001_Single_Phase_Fault_Precipitates_Loss_of_Generation_and_Load.pdf
3 https://www.nerc.com/pa/rrm/ea/Pages/July_2020_San_Fernando_Disturbance_Report.aspx

Requested information
c. R4.1.1 and 4.1.2, the stability performance criteria should be applicable to both synchronous and asynchronous generation, inclusive of DER. d. R4.3.2, the list of dynamic control devices should include DER so that the expected automatic operation of DER (e.g., DER tripping, dynamic voltage and frequency controls, momentary cessation, etc.) can be considered in stability analyses. e. Assuming that revisions to the MOD-032 standard ensure that DER model data is available, modification to the TPL-001 standard should give consideration to potential exclusions of explicit DER modeling based on technical rationale.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[4] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
A detailed description of each Project Scope item is given below: a. R2.1 and R2.2, the use of phrase "System peak Load" With increased penetration of DER, the load that transmission system supplies is the net load (net load = gross load – DER output) as seen at the T-D interface, which might reach its peak during operating conditions that are not at the peak gross load hour. As such, there is a need for individual TPs to be required to document and define their peak load conditions (e.g., gross or net) in their assessments. The SDT should consider adding the terms "Gross Load" and "Net Load" to the NERC Glossary of Terms and updating the term "System peak Load" in the standard to "System peak net Load". In addition, a high gross load hour may be the most stressed load driven condition for contingencies that may trip large amounts of DER. High system peak gross load may be studied as additional scenarios as required by current standard under R2.1.3. b. R3.3.1.1 and R4.3.1.2, the "tripping of generators" in steady state and stability contingency analysis should include tripping of DER if data is available. The SDT can consider whether a threshold needs to be established. The terms "generators" in Sub-requirements 3.3.1.1 and 4.3.1.2 should be clarified. DERs that are explicitly modeled as generators should be tripped where simulations show bus voltages that are less than known or assumed minimum DER steady-state or ride-through voltage limits. It is also recommended to consider inclusion in the assessment any assumptions made in estimating DER bus voltage.

[4] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
c. R4.1.1 and 4.1.2, the stability performance criteria should be applicable to both synchronous and asynchronous generation, inclusive of DER. For example, the language referring to "pulls out of synchronism" is only relevant to synchronous generation and is not applicable to inverter-based generation (including inverter-based DER). However, large amounts of asynchronous DER tripping on low/high voltage/frequency conditions can also adversely affect BES performance and may pose a risk to system instability for conditions such as cascading, voltage instability, or uncontrolled islanding if not properly studied and identified ahead of real-time operations. It is recommended to expand the stability performance criteria to include both synchronous and asynchronous generation. d. R4.3.2, the standard should recognize that the list of dynamic control devices should consider the expected automatic operation of DER (e.g., DER tripping, dynamic voltage and frequency controls, momentary cessation, etc.) in stability analyses. The SDT can consider adding asynchronous generator related devices like inverter, plant controller, etc.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Although the cost impact is unknown, costs to Planning Coordinators and Transmission Planners will increase as Transmission System Planning Assessments reflect additional dynamic components and controls. It is anticipated that this cost will vary depending on training, tools, scenario development, and other factors in each Planning Coordinators and Transmission Planners' area.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None. This SAR will primarily impact Transmission System Planning Assessments, not any specific BES facilities, although as individual IBRs continue to increase in size (e.g. 14MW wind turbines), there may be some impact in the near future.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Planning Coordinators and Transmission Planners, i.e. the applicable entities for this standard. Additionally, Distribution Providers, Generator Owners, and DER aggregators participating in markets- i.e. not an applicable entity to this standard, would be useful to include.

Requested information
Do you know of any consensus building activities[5] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This SAR is the outcome of the following white paper that was developed by the NERC technical sub-group under the RSTC. • SPIDERWG: Assessment of DER impacts on NERC Reliability Standard TPL-001 (here) Deliverables, and the key findings and recommendations contained within, were thoroughly reviewed and approved by the RSTC.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
No
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
Among all the issues identified in the NERC SPIDERWG white paper, the ones included in this SAR cannot be addressed by any alternatives. Standard language change will ensure DER impacts being considered appropriately. NERC SPIDERWG will prepare a Reliability Guideline to address the rest of the findings from their white paper.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
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Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
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4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	None

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Date Submitted:	12/15/2021 (Revised on June 22, 2022)		
SAR Requester			
Name:	Kun Zhu, MISO (NERC SPIDERWG Chair) Bill Quaintance, Duke Energy Progress (NERC SPIDERWG Vice-Chair) (Revised by Project 2022-02 SAR Drafting Team)		
Organization:	NERC System Planning Impacts from DERs Working Group (SPIDERWG)		
Telephone:	Kun – 317-249-5789 Bill – 919-546-4810	Email:	kzhu@misoenergy.org william.quaintance@duke-energy.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☒ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☒ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
Many distribution systems connected both directly and indirectly ~~areas of~~ to the North American BES are experiencing increasing penetrations of distributed energy resources (DERs). NERC Reliability Standard TPL-001-5.1[1] was developed under a paradigm of predominantly BPS-connected generation, particularly synchronous generation, when penetrations of DERs were significantly lower than current and future projections. Considering current trends, the NERC SPIDERWG undertook a review of the TPL-001 standard considering the potential impact of DERs. This review is captured in the following RSTC-approved white paper and serves as the technical justification for the revisions suggested in this SAR:			

[1] The scope of recent modifications to TPL-001-5 did not include considering the impacts of DER on BES~~BPS~~ planning.

Requested information

- SPIDERWG: Assessment of DER impacts on NERC Reliability Standard TPL-001 (here)

This SAR proposes to update TPL-001-5.1 to address some of the issues identified in the white paper.

TPL-001-5.1 does not currently require Planning Coordinators and Transmission Planners to complete Planning Assessments with adequate representation of the dynamic behavior of DERs. As the penetration of DERs increases, and based on the DER data and models available, Planning Assessments should include DERs that can potentially impact Transmission System performance assessment. NERC's "Lesson Learned: Single Phase Fault Precipitates Loss of Generation and Load", evaluating a 2019 frequency event in Southern England exacerbated by the unexpected reduction of 725 MW of IBR output and the unexpected loss of 350 MW of DER, highlights the critical importance of accurate Transmission System Planning Assessments.[2] In July 2020, a significant quantity of solar PV facilities across a large geographic area in Southern CA reduced about 1000 MW output due to a disturbance on the bulk power system[3]. Subsequent event analysis revealed that it was the consequence of momentary cessation and slow recovery of power. Standards enhancement has been one of the recommendations after the event analysis to ensure reliable operation of the bulk power system.

In general, the impact of DERs on the BES should be included in planning assessments if DER data and models are available. Any choice to exclude the consideration of the impact of DER on the BES should be supported by a technical rationale and/or justification.

Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):

The purpose of this SAR is to revise requirements to provide clarity or, in some cases, expand the scope of requirements when considering the performance of DERs to ensure the accuracy of Transmission System Planning Assessments.

Project Scope (Define the parameters of the proposed project):

As identified by SPIDERWG, revision to the following sections of TPL-001-5.1 should be considered~~revised~~ to ensure the accuracy of Transmission System Planning Assessments:

a. R2.1, R2.2, and R2.4~~2~~, the use of phrase "System peak Load"
b. R3.3.1.1 and R4.3.1.2, the "tripping of generators" in steady state and stability contingency analysis should include tripping of DER if data and models are available. The SDT can consider whether a threshold needs to be established.

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[2] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20201001_Single_Phase_Fault_Precipitates_Loss_of_Generation_and_Load.pdf

[3] https://www.nerc.com/pa/rrm/ea/Pages/July_2020_San_Fernando_Disturbance_Report.aspx

Requested information
c. R4.1.1 and 4.1.2, the stability performance criteria should be applicable to both synchronous and asynchronous generation, inclusive of DER. d. R4.3.2, the list of dynamic control devices should include DER so that the expected automatic operation of DER (e.g., DER tripping, dynamic voltage and frequency controls, momentary cessation, etc.) can be considered in stability analyses. ~~d.~~e. Assuming that revisions to the MOD-032 standard ensure that DER model data is available, modification to the TPL-001 standard should give consideration to potential exclusions of explicit DER modeling based on technical rationale.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[4] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
A detailed description of each Project Scope item is given below: a. R2.1 and R2.2, the use of phrase "System peak Load" With increased penetration of DER, the load that transmission system supplies is the net load (net load = gross load – DER output) as seen at the T-D interface, which might reach its peak during operating conditions that are not at the peak gross load hour. As such, there is a need for individual TPs to be required to document and define their peak load conditions (e.g., gross or net) in their assessments. The SDT should consider adding the terms "Gross Load" and "Net Load" to the NERC Glossary of Terms and updating the term "System peak Load" in the standard to "System peak net Load". In addition, a high gross load hour may be the most stressed load driven condition for contingencies that may trip large amounts of DER. High system peak gross load may be studied as additional scenarios as required by current standard under R2.1.3. b. R3.3.1.1 and R4.3.1.2, the "tripping of generators" in steady state and stability contingency analysis should include tripping of DER if data is available. The SDT can consider whether a threshold needs to be established. The terms "generators" in Sub-requirements 3.3.1.1 and 4.3.1.2 should be clarified. DERs that are explicitly modeled as generators should be tripped where simulations show bus voltages that are less than known or assumed minimum DER steady-state or ride-through voltage limits. It is also recommended to consider inclusion in the assessment any assumptions made in estimating DER bus voltage.

[4] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
c. R4.1.1 and 4.1.2, the stability performance criteria should be applicable to both synchronous and asynchronous generation, inclusive of DER. For example, the language referring to “pulls out of synchronism” is only relevant to synchronous generation and is not applicable to inverter-based generation (including inverter-based DER). However, large amounts of asynchronous DER tripping on low/high voltage/frequency conditions can also adversely affect BES performance and may pose a risk to system instability for conditions such as cascading, voltage instability, or uncontrolled islanding if not properly studied and identified ahead of real-time operations. It is recommended to expand the stability performance criteria to include both synchronous and asynchronous generation. d. R4.3.2, the standard should recognize that the list of dynamic control devices should consider the expected automatic operation of DER (e.g., DER tripping, dynamic voltage and frequency controls, momentary cessation, etc.) in stability analyses. The SDT can consider adding asynchronous generator related devices like inverter, plant controller, etc.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Although the cost impact is unknown, costs to Planning Coordinators and Transmission Planners will increase as Transmission System Planning Assessments reflect additional dynamic components and controls. It is anticipated that this cost will vary depending on training, tools, scenario development, and other factors in each Planning Coordinators and Transmission Planners’ area.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None. This SAR will primarily impact Transmission System Planning Assessments, not any specific BES facilities, although as individual IBRs continue to increase in size (e.g. 14MW wind turbines), there may be some impact in the near future.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Planning Coordinators and Transmission Planners, i.e. the applicable entities for this standard. Additionally, Distribution Providers, Generator Owners, and DER aggregators participating in markets- i.e. not an applicable entity to this standard, would be useful to include.

Requested information
Do you know of any consensus building activities[5] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This SAR is the outcome of the following white paper that was developed by the NERC technical sub-group under the RSTC. • SPIDERWG: Assessment of DER impacts on NERC Reliability Standard TPL-001 (here) Deliverables, and the key findings and recommendations contained within, were thoroughly reviewed and approved by the RSTC.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
No
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
Among all the issues identified in the NERC SPIDERWG white paper, the ones included in this SAR cannot be addressed by any alternatives. Standard language change will ensure DER impacts being considered appropriately. NERC SPIDERWG will prepare a Reliability Guideline to address the rest of the findings from their white paper.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

[5] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Market Interface Principles	
Does the proposed standard development project comply with all of the following [Market Interface Principles]?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	None

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk

4	February 25, 2020	Standards Information Staff	Updated template footer

CIP-008 Reporting Threshold

Action

- Accept the CIP-008 Reporting Threshold Standard Authorization Request (SAR);
- Authorize posting of the SAR for a 30-day informal comment period; and
- Authorize solicitation of the SAR drafting team (DT) members.

Background

Reliability Standard CIP-008-6 became effective on January 1, 2021, in response to FERC Order No. 848[1] directing NERC to develop modifications to the Reliability Standards to require reporting of Cyber Security Incidents and attempt(s) to compromise a responsible entity's Electronic Security Perimeter (ESP) or associated Electronic Access Control or Monitoring Systems (EACMS). In Q3 2021, the ERO Enterprise initiated a study to better understand how registered entities have implemented Reliability Standard CIP-008-6; specifically, how the registered entities have interpreted Reportable Cyber Security Incidents and defined attempt(s) to compromise. The study concluded the current language of the Reliability Standard permits the use of subjective criteria to define attempt(s) to compromise, and most programs include a provision allowing a level of staff discretion. Reliability Standard CIP-008-6 or definitions should be modified to provide a minimum expectation for thresholds defining attempt to compromise.

Since the effective date of CIP-008-6, there has not been a material change from CIP-008-5 in the number of Reportable Cyber Security Incidents or Cyber Security Incidents that were determined to be an attempt to compromise an applicable system. This project will address gaps in CIP-008-6 permitting a subjective determination of attempt(s) to compromise.

Summary

The Standard Drafting Team (SDT) will modify the Reliability Standards and associated definitions as necessary to provide a minimum expectation for thresholds to support the definition of attempt to compromise. Modifications should be focused on CIP-008-6, however, it may be necessary to modify other related standards for consistency.

[1] https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/E-1_Order%20No.%20848.pdf

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	CIP-008 Reporting Threshold		
Date Submitted:	18 July, 2022		
SAR Requester			
Name:	Michaelson Buchanan		
Organization:	NERC		
Telephone:	470.725.5268	Email:	Michaelson.buchanan@nerc.net
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☒ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
Improve awareness of existing and future cyber security risk to the BES.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
Since the effective date of CIP-008-6 there has not been a material change in the number of Reportable Cyber Security Incidents or Cyber Security Incidents that were determined to be an attempt to compromise an applicable system. This project will address gaps in CIP-008-6 permitting a subjective determination of attempt(s) to compromise.			
Project Scope (Define the parameters of the proposed project):			
The Standards Drafting Team (SDT) will modify the Reliability Standards and associated definitions as necessary to provide a minimum expectation for thresholds to support the definition of attempt to compromise. Modifications should be focused on CIP-008-6, however, it may be necessary to modify other related standards for consistency.			

Requested information
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
Reliability Standard CIP-008-6 became effective on January 1, 2021, in response to FERC Order No. 848[3] directing NERC to develop modifications to the Reliability Standards to require reporting of Cyber Security Incidents and attempt(s) to compromise a responsible entity's Electronic Security Perimeter (ESP) or associated Electronic Access Control or Monitoring Systems (EACMS). In Q3 2021, the ERO Enterprise initiated a study to better understand how registered entities have implemented Reliability Standard CIP-008-6; specifically, how the registered entities have interpreted Reportable Cyber Security Incidents and defined attempt(s) to compromise. The study concluded the current language of the Reliability Standard permits the use of subjective criteria to define attempt(s) to compromise, and most programs include a provision allowing a level of staff discretion. Reliability Standard CIP-008-6 or definitions should be modified to provide a minimum expectation for thresholds defining attempt to compromise. To accomplish this, CIP-008-6 R1 Part 1.2.1 could be modified to read, "...That include criteria to evaluate and define attempts to compromise which include, at a minimum, each of the following types of cyber security incidents:…". Conversely, it may be possible to modify the NERC Glossary definition of Reportable Cyber Security Incident to include attempt to compromise along with threshold criteria. There are other examples in the NERC Glossary of Terms, such as Removable Media which include minimum expectation examples. These are examples and not the only possible solutions. Regardless of the approach, thresholds should not be so prescriptive as to require the reporting of every internet facing firewall port scan, phishing email identified, or file alerted by endpoint anti-virus scans. Rather, the intent would be to right size the reporting threshold to improve awareness of existing and future cyber security risks to the BES.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
No additional cost outside of the time and resources needed to serve on the Standard Drafting Team are expected. However, a question will be asked during the SAR comment period to ensure all aspects are considered.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Balancing Authority, Distribution Provider, Generator Operator, Generator Owner, Reliability Coordinator, Transmission Operator, Transmission Owner

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
In Q3-2021, the NERC Compliance Assurance and ERO Enterprise initiated a study to better understand how registered entities have implemented Reliability Standard CIP-008-6 in response to modifications; specifically, how the registered entities are interpreting Reportable Cyber Security Incidents and defining attempt(s) to compromise. The study team reviewed previous compliance monitoring engagements to analyze ERO Enterprise CMEP data and conducted a questionnaire engagement with approximately 30 registered entities through voluntary mechanisms (e.g., entity engagements, webinars, onsite visits, etc.). The questionnaires focused on four key areas: 1) criteria for reporting and key definitions, 2) organizational internal controls, 3) training and tools, and 4) reporting. The study concluded that the current language of the Reliability Standard permits the use of subjective criteria to define attempt to compromise, and most programs included a provision which allows a level of discretion by staff. Other aspects of the CIP-008 Reliability Standard were found to be sufficient.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
2016-02 includes modifications to the applicable systems listed in CIP-008-6. Once approved, CIP-008-6 will increment to CIP-008-7.
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
None.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☐	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.
[3] Cyber Security Incident Reporting Reliability Standards, Order No. 848, 164 FERC ¶ 61,033 (2018).

Reliability Principles	
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☒	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following [Market Interface Principles]?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
N/A	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised

2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Project 2021-08 Modifications to FAC-008

Action

- Accept the Project 2021-08 Modifications to FAC-008 Standard Authorization Request (SAR);
- Authorize drafting revisions to the Reliability Standard identified in the SAR; and
- Appoint the Project 2021-08 SAR Drafting Team (DT) as the Project 2021-08 Standard Drafting Team (SDT).

Background

The Project 2021-08 SAR seeks to modify Reliability Standard FAC-008 to address the inconsistent understanding of “jointly owned” as well as the concern of non-electrical equipment in the determination of Generator Owner Facility Ratings (Requirement R1).

At the October 20, 2021 meeting, the Standards Committee (SC) accepted the SAR. At the same meeting, the SC authorized soliciting for members for the SAR DT. The formal comment period for the SAR and the solicitation for the SAR Drafting Team occurred from December 9, 2021 to January 27, 2022.

At the April 20, 2022 meeting, the SC appointed chair, vice chair, and members to the Project 2021-08 Modifications to FAC-008 Standard Authorization Request (SAR) drafting team (DT).

The SAR DT met 13 times (including the Project kickoff meeting) from May 10, 2022 through August 16, 2022 to review and make revisions to the SAR. The team discussed and considered industry comments during this process.

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	FAC-008 Facility Ratings		
Date Submitted:	07-14-2021 (Revised on August 16, 2022)		
SAR Requester			
Name:	Ryan Walter (Revised by Project 2021-08 SAR Drafting Team)		
Organization:	Tri-State Generation and Transmission Association, Inc.		
Telephone:	303-254-3722	Email:	rwalter@tristategt.org
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☒ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
Produce Generator Owner Facility Ratings that accurately reflect the real power capability of the facility and are therefore useful for reliability-related activities (such as in contingency analysis, SOL determination, etc). Additionally, provide clarification around the phrase "jointly owned" and the level of individual component ratings that are required to be shared with the other entity. This will ensure clear expectations are set such that there are no gaps or conflicts between interconnecting entities.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
The Standard Drafting Team will review Requirement 1 and determine changes, if any, which are necessary to ensure reliability while removing redundancy and administrative burdens from the standard.			

Requested information
Further, the term “jointly owned” as used in FAC-008-5 allows for inconsistent application across the ERO. The Standard Drafting team should examine the appropriate level of data sharing between entities to support consistent Facility Ratings and support the development of System Operating Limits. Ensure that Requirement R6 is reviewed as a risk-based Requirement.
Project Scope (Define the parameters of the proposed project):
The scope of this project would be to modify FAC-008 and any associated defined terms to address the following: 1. Clarify the term “jointly owned” as it applies to FAC-008, and what information is required to be shared with neighboring entities. 2. Examine the appropriateness and effectiveness of Requirement 1 for the development of Facility Ratings information for Generation Facilities. 3. Ensure that Requirement R6 is reviewed as a risk-based Requirement.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
Requirement R1 of the FAC-008 Standard will be examined to determine its continued effectiveness. Since the development of FAC-008 there have been several additional Reliability Standards developed which request similar or redundant information as FAC-008 Requirement 1. The additional standards that can be considered are IRO-010, MOD-025, MOD-032, TOP-003, and possibly others. The Standard Development Team will review Requirement 1 and determine changes, if any, which are necessary to ensure reliability while removing redundancy and administrative burdens from the standard. Generator Facility Ratings and capability information must be accurate to establish maximum capabilities for RC, TOP, and BA network models, resource adequacy studies, operational and contingency studies, outage reporting, and emergency response, as is reflected in FERC Order Approving Reliability Standard FAC-008-3 (Docket RD11-10-000), paragraph 10, “NERC states that the standard drafting team interpreted this directive to allow reliability entities to take rating information and prepare operating plans or planning assessments prior to real-time, which could allow for better situational awareness and improved reliability of the bulk electric system.” The burden of Facility Rating documentation is unclear in ‘jointly-owned’ facilities. The ERO Enterprise CMEP Practice Guide interprets this burden as each owner maintaining all the equipment ratings of their own equipment and the Most Limiting Series Element of the ‘jointly-owned’ owner. This burden

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
has been inconsistently understood. The SDT should examine the appropriate level of data sharing between entities to support consistent Facility Ratings and support the development of System Operating Limits. If the SDT determines that Facility Ratings data is required to be shared between owners, the SAR DT suggests that the applicable entity should be required to provide the most limiting equipment rating for its jointly owned facilities. For Generation Owners specifically, Requirement 2 obligates GOs to obtain Facility Rating information from the interconnecting Owners of jointly owned Facilities. However, the requirement R8 does not provide the Generator Owner with the authority to request Facility Rating information from other entities. Per the requirement, Facility owners only need to provide request Facility Rating information to the following entities: Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s). Without modifications, Generator Owners are placing in a situation where they are required to have data that they may not be able to obtain. Additionally, Requiring Generator Owners to obtain rating information from interconnecting Transmission Owners of jointly owned Facilities provides no additional benefit to reliability and is an administrative burden that can be eliminated. Generator Owners do not develop SOLs and should only be obligated to provide data for the equipment they own. The use of the term “consistent” in Requirement R6 can be interpreted that all inconsistencies in Facility Ratings pose an equal risk to the BES. The SAR team suggests data errors not affecting the overall Facility Rating does not produce a risk to the BES nor is it inconsistent with the statement that ‘a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that facility.’ The SDT shall consider additional wording/guidance to ensure the standard is focused on BES reliability rather than data collection. The objectives of this SAR could be addressed in various ways. Here are a few ideas: 1. Alter, modify, or eliminate FAC-008, R1 to provide information necessary for the development of appropriate planning models and system operating limits. 2. The SDT will review the use of the term “jointly owned” and clarify, modify, or eliminate its use from the FAC-008 Reliability Standard. 3. Review the language of Requirements 1, 2, 3, 6, and 8, and the “Compliance Assessment Approach” section of the RSAW. Determine if additional guidance or modifications are required to ensure R6 is risk based in nature.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Cost impacts for these changes should be minimal. Entities would potentially need to reevaluate Generator Facility Ratings and associated Facility Rating documentation.

Requested information
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None identified at this time.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Transmission Owner, Generator Owner
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
No
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
FAC-008-5 If any of the defined terms are modified, all other standards that utilize those terms will need to be assessed for compatibility.
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
An ERO Practice Guide, Compliance Guidance, Implementation Guidance, or Interpretation could be helpful to address these issues.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following [Market Interface Principles]?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g., NPCC	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	FAC-008 Facility Ratings		
Date Submitted:	07-14-2021 (Revised on August 16, 2022)		
SAR Requester			
Name:	Ryan Walter (Revised by Project 2021-08 SAR Drafting Team)		
Organization:	Tri-State Generation and Transmission Association, Inc.		
Telephone:	303-254-3722	Email:	rwalter@tristategt.org
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☒ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
Produce Generator Owner Facility Ratings that accurately reflect the real power capability of the facility and are therefore useful for reliability-related activities (such as in contingency analysis, SOL determination, etc). Additionally, provide clarification around the phrase “jointly owned” and the level of individual component ratings that are required to be shared with the other entity. This will ensure clear expectations are set such that there are no gaps or conflicts between interconnecting entities.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
~~As currently written, the FAC-008 Reliability Standard and associated defined terms “Facility” and “Element” have been interpreted by some to mean that only electrical components may be considered when developing Generator Facility Ratings under R1. This could lead to planning and operational entities being provided Generator Facility Ratings that are higher than the actual output the plant is~~			

Requested information
~~capable of, which could be detrimental to reliability during actual system emergencies. Explicitly allowing the inclusion of mechanical elements in the development of Facility Ratings will ensure Generators are rated to their most limiting element.~~ The Standard Drafting Team will review Requirement 1 and determine changes, if any, which are necessary to ensure reliability while removing redundancy and administrative burdens from the standard. Further, the term “jointly owned” as used in FAC-008-~~3~~ 5 ~~non-formal use of the term “jointly owned”~~ ~~is ambiguous when compared with the industry legacy use of “jointly owned” as a purely financial and contractual obligation. This lack of clarity of intent of the standard could cause risk of facility rating gaps, misunderstanding of rating overlap requirements or gaps in facility rating coordination that could be resolved by clearly defining the technical expectations of the term “jointly owned”.~~ allows for inconsistent application across the ERO. The Standard Drafting team should examine the appropriate level of data sharing between entities to support consistent Facility Ratings and support the development of System Operating Limits. Ensure that Requirement R6 is reviewed as a risk-based Requirement.
Project Scope (Define the parameters of the proposed project):
The scope of this project would be to modify FAC-008 and any associated defined terms to address the following: 1. Clarify the term “jointly owned” as it applies to FAC-008, and what information is required to be shared with neighboring entities. 2. ~~Permit inclusion of non-electrical equipment in the determination of GO Facility Ratings (R1).~~ Examine the appropriateness and effectiveness of Requirement 1 for the development of Facility Ratings information for Generation Facilities. 3. Ensure that Requirement R6 is reviewed as a risk-based Requirement.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
Requirement R1 of the FAC-008 Standard will be ~~modified to allow Generator Owners the flexibility to include all applicable equipment at their facilities when determining their Facility Ratings. As currently written, some have interpreted requirement R1 to restrict Facility Ratings to only include electrical~~

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
~~components. Generation facilities are often mechanically restricted by the performance capabilities of the turbines installed. By not allowing non-electrical equipment to be included, the GO may be developing and sharing Facility Ratings that are higher than the facility is actually capable. One possible solution to remedy this in the requirement is to add language permitting the inclusion of mechanical limitations, so long as the most limiting electrical component is not exceeded.~~examined to determine its continued effectiveness. Since the development of FAC-008 there have been several additional Reliability Standards developed which request similar or redundant information as FAC-008 Requirement 1. The additional standards that can be considered are IRO-010, MOD-025, MOD-032, TOP-003, and possibly others. The Standard Development Team will review Requirement 1 and determine changes, if any, which are necessary ~~to provide~~ to ensure reliability while removing redundancy and administrative burdens from the standard. Generator Facility Ratings and capability information must be accurate to establish maximum capabilities for RC, TOP, and BA network models, resource adequacy studies, operational and contingency studies, outage reporting, and emergency response, as is reflected in FERC Order Approving Reliability Standard FAC-008-3 (Docket RD11-10-000), paragraph 10, "NERC states that the standard drafting team interpreted this directive to allow reliability entities to take rating information and prepare operating plans or planning assessments prior to real-time, which could allow for better situational awareness and improved reliability of the bulk electric system." The burden of Facility Rating documentation is unclear in 'jointly-owned' facilities. The ERO Enterprise CMEP Practice Guide interprets this burden as each owner maintaining all the equipment ratings of their own equipment and the Most Limiting Series Element of the 'jointly-owned' owner. This burden has been inconsistently understood. The SDT should examine the appropriate level of data sharing between entities to support consistent Facility Ratings and support the development of System Operating Limits. If the SDT determines that Facility Ratings data is required to be shared between owners, the SAR DT suggests that the applicable entity should be required to provide the most limiting equipment rating for its jointly owned facilities. For Generation Owners specifically, Requirement 2 obligates GOs to obtain Facility Rating information from the interconnecting Owners of jointly owned Facilities. However, the requirement R8 does not provide the Generator Owner with the authority to request Facility Rating information from other entities. Per the requirement, Facility owners only need to provide request Facility Rating information to the following entities: Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s). Without modifications, Generator Owners are placing in a situation where they are required to have data that they may not be able to obtain. Additionally, Requiring Generator Owners to obtain rating information from interconnecting Transmission Owners of jointly owned Facilities provides no additional benefit to reliability and is an administrative burden that can be eliminated. Generator Owners do not develop SOLs and should only be obligated to provide data for the equipment they own.

Requested information

The use of the term "consistent" in Requirement R6 can be interpreted that all inconsistencies in Facility Ratings pose an equal risk to the BES. The SAR team suggests data errors not affecting the overall Facility Rating does not produce a risk to the BES nor is it inconsistent with the statement that 'a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that facility.' The SDT shall consider additional wording/guidance to ensure the standard is focused on BES reliability rather than data collection.

The objectives of this SAR could be addressed in various ways. Here are a few ideas:

1. Alter, modify, or eliminate ~~the language within~~ FAC-008, R1 to provide information necessary for the development of appropriate planning models and system operating limits.~~explicitly allow the inclusion of non-electrical components in Generator Facility Ratings documentation.~~
2. ~~Generate a new NERC Defined term "Generation Facility"- This term would include the current NERC Glossary Term for "Facility", but amend that definition to include the mechanical components of the generating plants.~~
   a. ~~R1 would then need to be modified to include this new definition where it currently utilizes the current definition of Facility.~~
3. ~~Alter/expand the current definition of "Facility" to include components beyond "electrical components" as currently stated.~~
4. ~~For "jointly owned" facilities, the following are potential solutions:~~
   a. ~~Add the term "electrically joined facilities" to the TO requirements, as it has been done in PRC-027-1. Here is an example:~~
   ~~*"R3. Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely owned, jointly owned, and electrically joined Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following:"*~~
   b. ~~Better define what "jointly owned" means by adding an applicable Facilities section, or a Standard Only Definition section, to the standard. For instance, the new Section could read:~~
   ~~*Jointly Owned Facilities- a set of Element(s) at a single physical location where more than one Registered Entities are financially responsible for the repair, replacement, or installation of equipment at that site.*~~
2. ~~Better define what "jointly owned" means by creating implementation compliance guidance similar to the "CIP-002-5.1a R1 Shared Ownership of BES Facilities (CIPC)" implementation guidance.~~The SDT will review the use of the term "jointly owned" and clarify, modify, or eliminate its use from the FAC-008 Reliability Standard.

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Requested information
3. Review the language of Requirements 1, 2, 3, 6, and 8, and the "Compliance Assessment Approach" section of the RSAW. Determine if additional guidance or modifications are required to ensure R6 is risk based in nature.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Cost impacts for these changes should be minimal. Entities would potentially need to reevaluate Generator Facility Ratings and associated Facility Rating documentation. ~~to include mechanical limitations.~~ ~~Depending upon an entity's current state and understanding of "jointly owned", as it pertains to Transmission Facilities, additional resources could be required to perform facility ratings calculations and methodology changes consistent with the determined language from item 4 above.~~
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
~~Generators, unlike the Transmission system of the electric grid, can be limited by both electrical and mechanical components. To correctly plan and operate the Bulk Electric System, Planning and Transmission Operations personnel need to be apprised of a generator's actual limitations regardless of limiting factor.~~ ~~Coordination of Facility Ratings for formally defined "jointly owned" or "electrically joined" equipment could take time and require new coordination efforts between adjacent entities.~~None identified at this time.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Transmission Owner, Generator Owner
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
No
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
FAC-008-5~~, FAC-008-3~~ If any of the defined terms are modified, all other standards that utilize those terms will need to be assessed for compatibility.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Requested information
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
An ERO Practice Guide, Compliance Guidance, Implementation Guidance, or Interpretation could be helpful to address these issues.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g., NPCC	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Project 2021-01 Modifications to MOD-025 and PRC-019

Action
Authorize initial posting of proposed Reliability Standards MOD-025-3 and PRC-019-3, and the associated Implementation Plans for a 45-day formal comment period, with ballot pool formed in the first 30 days, and parallel initial ballot and non-binding polls for the Violation Risk Factors and Violation Severity Levels, conducted during the last 10 days of the comment period.

Background
This project was undertaken to address issues identified in three Standard Authorization Requests (SARs).

First, the Power Plant Modelling and Verification Task Force (PPMVTF) developed a SAR to revise MOD-025-2 to address issues regarding verification and data reporting of generator active and reactive power capability. The SAR aims to retain testing activities that are useful and focus on more effective means of collecting useful data for planning models. The Reliability and Security Technical Committee (RSTC) endorsed the SAR on October 14, 2020. The Standards Committee (SC) later accepted the SAR on January 20, 2021.

Second, the System Protection and Control Subcommittee (SPCS) drafted a SAR to address a number of issues identified and revise the standard to be inclusive of all types of generation resources. Currently, PRC-019-2 addresses the reliability issue of miscoordination between generator capability, control systems, and protection functions. However, PRC-019-2 was developed with a bias toward synchronous generation and does not sufficiently outline the requirements for all generation resource types. The NERC Planning Committee (PC) endorsed the SAR on March 4, 2020. The SC later accepted the SAR on January 20, 2021.

Third, the System Analysis and Modeling Subcommittee (SAMS) developed the *Applicability of Transmission-Connected Reactive Devices* white paper, and an associated SAR, in response to the potential risk of increasing amounts of reactive power being supplied by nonsynchronous sources. The PC endorsed the SAR on February 11, 2020. The SC later accepted the SAR on March 18, 2020.

To address the issues outlined in the three SARs, the SC appointed a single SAR Drafting Team (DT) on July 21, 2021. The SAR DT met August – October 2021 to review and revise the SARs. The scope of the Transmission-Connected Reactive Devices SAR was integrated into the MOD-025 and PRC-019 SARs. On December 15, 2021, the SC appointed the SAR DT as the Standard Drafting Team (SDT) and authorized revisions to MOD-025-2 and PRC-019-02.

Summary
The SDT held conference calls January – August 2022 to revise MOD-025-2 and PRC-019-2. The Quality Review (QR) for this posting was performed August 4 – 29, 2022. Electric Reliability Organization Enterprise staff reviewing MOD-025-3 and PRC-019-3 included Rachel Coyne, Steve Rueckert, Al McMeekin, Jon Hoffman, Lauren Perotti, Jamie Calderon, and Wendy Muller. Industry QR members for MOD-025-3 included Bryan Burch (Southern Company) and Shawn Patterson (USBR). Industry QR members for PRC-019-3 included Manish Patel (Southern

Company). The SDT reviewed all comments and revised the proposed Reliability Standards and Implementation Plans where appropriate.

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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	March 4 – April 2, 2021

Anticipated Actions	Date
45-day formal or informal comment period with ballot	September – November 2022
45-day formal or informal comment period with additional ballot	February – April 2023
10-day final ballot	May 2023
Board adoption	August 2023

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:** Verification of Real and Reactive Power Capability for BES Facilities

2. **Number:** MOD-025-3

3. **Purpose:** To ensure that accurate information on Bulk Electric System (BES) Facility Real and Reactive Power capability is available for planning models used to assess BES reliability.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Generator Owner

   4.1.2 Transmission Owner

   4.1.3 Transmission Planner

   4.2. Facilities:

   For the purpose of this standard, the term, "applicable Facility" or "Facility" shall mean any one of the following:

   4.2.1 Individual generating resource identified through Inclusion I2 of the BES definition.

   4.2.2 Generating plant/Facility identified through Inclusion I2 of the BES definition.

   4.2.3 Generating plant/Facility of dispersed power producing resources identified through Inclusion I4 of the BES definition.

   4.2.4 Dynamic reactive devices identified through Inclusion I5 of the BES definition with a gross (individual or aggregate) nameplate rating greater than 20 MVA including, but not limited to:

   4.2.4.1 Synchronous condenser; and

   4.2.4.2 Flexible alternating current transmission system (FACTS) devices.

   4.2.5 HVDC terminal equipment including:

   4.2.5.1 Voltage source converter (VSC).

5. **Effective Date:** see Project 2021-01 Modifications to MOD-025 and PRC-019 Implementation Plan

B. Requirements and Measures

R1. Each Generator Owner shall verify the Real Power and Reactive Power capability of its applicable Facilities and inform its Transmission Planner as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Verify the Real Power capability, if applicable, of its applicable Facilities in accordance with Attachment 1.

1.2. Verify the Reactive Power capability of its applicable Facilities in accordance with Attachment 1.

1.3. Submit the following information, in accordance with Attachment 2, to the Transmission Planner within 30 calendar days after the verification date:

1.3.1. One-line diagram representing the Facility;

1.3.2. Composite capability curve and associated PQ data table; and

1.3.3. Documentation showing the engineering basis, verification methodology and/or applicable data for the verification method.

M1. Each Generator Owner shall have evidence that it verified Real Power and Reactive Power capability of each Facility, such as completed attachments or summary report(s); and have evidence that it submitted the information within 30 calendar days after the verification date to its Transmission Planner in accordance with Requirement R1.

R2. Each Transmission Owner shall verify the Real Power and Reactive Power capability of its applicable Facilities and inform its Transmission Planner as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Verify the Real Power capability, if applicable, of its applicable Facilities in accordance with Attachment 1.

2.2. Verify the Reactive Power capability of its applicable Facilities, in accordance with Attachment 1.

2.3. Submit the following information per Attachment 2 to the Transmission Planner within 30 calendar days after the verification date:

2.3.1. One-line diagram representing the Facility;

2.3.2. Composite capability curve and associated PQ data table; and

2.3.3. Documentation showing the engineering basis, verification methodology and/or applicable data for the verification method.

M2. Each Transmission Owner shall have evidence that it verified Real Power and Reactive Power capability of each Facility, such as completed attachments or summary report(s); and have evidence that it submitted the information within 30 calendar days after the verification date to its Transmission Planner in accordance with Requirement R2.

R3. Each Transmission Planner shall review the information submitted by each Generator Owner or Transmission Owner in accordance with Requirement R1, R2, or R4 and provide a written response within 90 calendar days containing one of the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Notification that the Transmission Planner has not identified any technical concerns with the Real and Reactive Power capability information submitted by the Generator Owner or Transmission Owner; or
- Notification that the Transmission Planner has identified a technical concern, including the basis for the technical concern.

M3. Each Transmission Planner shall have evidence, such as a summary of items reviewed and dated correspondence of the notification, that it reviewed the information submitted and provided notification to the Generator Owner or Transmission Owner within 90 calendar days in accordance with Requirement R3.

R4. Each Generator Owner or Transmission Owner receiving a notification of a technical concern under Requirement R3 shall provide a written response to its Transmission Planner within 90 calendar days containing one of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Updated capability information in accordance with Requirements R1 or R2;
- A mutually agreed upon plan with its Transmission Planner to update the capability information in accordance with Requirements R1 or R2; or
- Technical justification and supporting evidence for maintaining the existing capability information in accordance with Requirements R1 or R2.

M4. Each Generator Owner or Transmission Owner shall have evidence that it responded to the Transmission Planner within 90 calendar days in accordance with Requirement R4.

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 shall keep data or evidence of Requirement R1 since the most current verification for each applicable BES Facility.
- Each Transmission Owner shall keep data or evidence of Requirement R2 since the most current verification for each applicable BES Facility.
- Each Transmission Planner shall keep data or evidence of Requirement R3 for a rolling 12 month period.
- Each Generator Owner and Transmission Owner shall keep data or evidence of Requirement R4 for a rolling 12 month period.

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.	The applicable entity provided all items in Requirement R1, but did so between 31 and 90 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 3, but did so between 10 years (120 calendar months) and 126 calendar months. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but	The applicable entity provided all items in Requirement R1, but did so between 91 and 180 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power, but failed to include the information required in Requirement R1, Part 1.3.1. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 3, but did so between 127 and 132 calendar months. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but	The applicable entity provided all items in Requirement R1, but did so between 181 and 270 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power, but failed to include the information required in Requirement R1, Part 1.3.3. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 3, but did so between 133 and 138 calendar months. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but	The applicable entity provided all items in Requirement R1, but did so greater than 270 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power, but failed to include the information required in Requirement R1, Part 1.3.2. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 3, but did so in more than 138 calendar months. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but did

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	did so between 181 and 270 calendar days.	did so between 271 and 360 calendar days.	did so between 361 and 450 calendar days.	so in more than 450 calendar days. OR The applicable entity failed to verify the Real and/or Reactive Power capability.
R2.	The applicable entity provided all items in Requirement R2, but did so between 31 and 90 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 3, but did between 10 years (120 calendar months) and 126 calendar months. OR	The applicable entity provided all items in Requirement R2, but did so between 91 and 180 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power, but failed to include the information required in Requirement R2, Part 2.3.1. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 3, but did so between 127 and 132 calendar months. OR	The applicable entity provided all items in Requirement R2, but did so between 181 and 270 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power, but failed to include the information required in Requirement R2, Part 2.3.3. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 3, but did so between 133 and 138 calendar months. OR	The applicable entity provided all items in Requirement R2, but did so greater than 270 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power, but failed to include the information required in Requirement R2, Part 2.3.2. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 3, but did so in more than 138 calendar months. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but did so between 181 and 270 calendar days.	The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but did so between 271 and 360 calendar days.	The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but did so between 361 and 450 calendar days.	The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but did so in more than 450 calendar days. OR The applicable entity failed to verify the Real and/or Reactive Power capability.
R3.	The Transmission Planner provided a written response to the submitter, but it was provided between 91 to 120 calendar days after receiving the verified model information.	The Transmission Planner provided a written response to the submitter, but it was provided between 121 to 150 calendar days after receiving the verified model information.	The Transmission Planner provided a written response to the submitter, but it was provided between 151 to 180 calendar days after receiving the verified model information.	The Transmission Planner failed to provide a written response to the submitter. OR The Transmission Planner provided a written response to the submitter but it was provided more than 180 calendar days after receiving the verified model information.
R4.	The applicable entity provided a written response to its Transmission Planner, but it was provided between 91 to 120 calendar days after	The applicable entity provided a written response to its Transmission Planner, but it was provided between 121 to 150 calendar days after	The applicable entity provided a written response to its Transmission Planner, but it was provided between 151 to 180 calendar days after	The applicable entity failed to provide a written response to its Transmission Planner. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	receiving a notification of technical concern.	receiving a notification of technical concern.	receiving a notification of technical concern.	The applicable entity provided a written response to its Transmission Planner, but it was provided greater than 180 calendar days after receiving a notification of technical concern.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	12/1/2005	1. Changed tabs in footer. 2. Removed comma after 2004 in “Development Steps Completed,” #1. 3. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 4. Added “periods” to items where appropriate. 5. Changed apostrophes to “smart” symbols. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all instances of “regional” in section D.3. 8. Removed the word “less” after 94% in section 3.4. Level 4.	01/20/06
2	February 7, 2013	Adopted by NERC Board of Trustees	Revised per SAR for Project 2007-09 and combined with MOD-024-1
2	March 20, 2014	FERC Order issued approving MOD-025-2. (Order becomes effective on 7/1/16.)	
3	Month XX, 2022	Adopted by NERC Board of Trustees	Revised per SAR for Project 2021-01

MOD-025-3 Attachments

MOD-025-3 Attachment 1 – Verification of Real and Reactive Power Capability for BES Facilities

Section I. Periodicity of verification:

The periodicity to verify the Real and Reactive Power capability for each applicable BES Facility is as follows:

1. The applicable entity designates the verification date and notates the verification date in a summary report (refer to Attachment 2). The verification date should represent the date that the engineering review or engineering analysis is complete. The verification date is the basis of the recurring periodicity.
2. Verify each new applicable Facility within 180 calendar days of its commercial operation date.
3. Verify each existing applicable Facility at a periodicity not to exceed ten years from the last verification date.
4. Verify an existing applicable Facility within 180 calendar days of the discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent increase or decrease of the nameplate rating and is expected to last more than 180 calendar days.
5. Verify an existing applicable Facility within 180 calendar days of its return to service date, if the Facility has a planned or unplanned outage of 180 days or more which overlaps its scheduled verification date and has not had its capability verified within the past ten years.

Section II. Verification specifications for applicable Facilities:

1. For individual devices or generators greater than 20 MVA (gross nameplate rating) perform verification on an individual basis.
2. For individual devices or generators 20 MVA (gross nameplate rating) or less that are part of an applicable Facility greater than 75 MVA (gross nameplate rating) in aggregate, perform verification on an individual unit basis or in the aggregate, considering applicable modeling expectations of the respective Transmission Planner.
3. Create a simplified key one-line diagram representing the Facility (refer to Attachment 2). The one-line diagram shall designate where the composite capability curve created in Section II, Items 6-8 is represented.
    3.1. The one-line representing the Facility shall include all auxiliary equipment expected to be in-service for normal operation, including dynamic and static reactive devices and auxiliary load, the GSU, and/or system interconnection

transformer(s), unit auxiliary transformer(s), and station services auxiliary transformer(s).

4. If an applicable Facility has no leading or lagging capability, then it should be reported with no leading or lagging capability.

5. The Generator Owner or Transmission Owner shall utilize and document one or more of the following methodologies to verify the Facility capability for all equipment expected to be in-service for normal operation. The engineering review or engineering analysis shall include underlying assumptions, design criteria, and methods used to create the Facility capability curve under Section II, Items 6-8.

    - Perform an engineering review of all Real and Reactive Power Facility capability information including but not limited to in-service equipment design limitations, excitation limiter settings, and operational limitations;
    - Utilize staged testing data, in accordance with Section III, obtained from a date within 365 calendar days prior to verification date, and perform engineering analysis as needed per Note 1, that validates the generator capability; or
    - Utilize operational data, in accordance with Section III, obtained from a date within 365 calendar days prior to verification date, and perform engineering analysis as needed per Note 1, that validates the generator capability.

6. For an applicable Facility as identified in Section 4.2.1, 4.2.2, or 4.2.4.1, when performing verification on an individual unit basis, create a graphical representation of the steady-state composite capability curve (CCC) for the Real Power and Reactive Power. The steady-state CCC shall include at a minimum the following:

    6.1. The generator steady-state Real Power and Reactive Power capability curve, or the synchronous condenser steady-state Reactive Power capability curve, provided by the equipment manufacturer.

        6.1.1 The curve shall represent generator/synchronous condenser capability at a nominal voltage of 1.0 per unit at the generator/synchronous condenser terminal; and

        6.1.2 The curve shall notate the operating conditions that dictate the power capability, for example H2 pressure, ambient temperature, or other conditions.

    6.2. Excitation limiters, if more restrictive than the equipment manufacturer's capability curve, at nominal voltage 1.0 per unit;

6.3. Identification of any Real Power or Reactive Power operational limitations[1], if applicable;

6.4. Identification of the steady-state minimum (P_{min}) and maximum (P_{max}) Real Power output at the generator terminal(s), based on the least restrictive seasonal or operating conditions; and

6.5. Identification of final PQ curve, which defines the normal operating region.

7. For an applicable Facility as identified in Section 4.2.2 or Section 4.2.3, when performing verification in aggregate, create a graphical representation of the steady-state composite capability curve (CCC) for the Real Power and Reactive Power. The steady-state CCC shall include at a minimum the following:

7.1. The steady-state Real and Reactive Power capability curve represented as an aggregate.

7.1.1 The curve shall represent Facility capability at a steady-state nominal voltage of 1.0 per unit at the common point of connection; and

7.1.2 The curve shall notate the operating conditions that dictate the power capability, for example H2 pressure, ambient temperature, or other conditions.

7.2. Aggregate Facility capability includes all auxiliary equipment expected to be in-service for normal operation, including dynamic and static reactive resources and auxiliary loads;

7.3. Identification of any Real Power or Reactive Power operational limitations, if applicable;

7.4. For inverter based resources, a description of all power plant controller and inverter control functions during normal operating conditions that dictate the aggregate Facility capability;

7.5. Identification of the steady-state minimum (P_{min}) and maximum (P_{max}) Real Power output at the common point of connection, based on the least restrictive seasonal or operating conditions; and

7.6. Identification of final PQ curve, which defines the normal operating region.

8. For an applicable Facility as identified in Section 4.2.4.2 and Section 4.2.5.1, create a graphical representation of the steady-state composite capability curve (CCC) for the Real Power and Reactive Power. The steady-state CCC shall include at a minimum the following:

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[1] Such as generator cooling, vibration, de-rated rotor, de-rated GSU transformer, generator bus de-rating, software limitations, or distributed control system (DCS) setpoints (outer-loop control system paths). This excludes fuel availability, such as water levels for hydro, cloud cover for PV, wind speed, or river level for run of river.

8.1. The HVDC steady-state Real Power and Reactive Power capability curve, or the FACTS device steady-state Reactive Power capability, provided by the equipment manufacturer.

8.1.1 The curve shall represent Facility capability at a steady-state nominal voltage of 1.0 per unit at the common point of connection ; and

8.1.2 The curve shall notate the operating conditions that dictate the power capability, for example ambient temperature or other conditions.

8.2. Any limiters, if more restrictive than the equipment manufacturer's capability curve(s), at nominal voltage 1.0 per unit;

8.3. Identification of any Real Power or Reactive Power operational limitations, if applicable;

8.4. A description of all control functions during normal operating conditions and a description of any Facility overload capabilities that dictate the aggregate Facility capability;

8.5. Identification of the steady-state minimum (P_{min}) and maximum (P_{max}) Real Power output at the common point of connection, based on the least restrictive seasonal or operating conditions; and

8.6. Identification of final PQ curve, which defines the normal operating region.

Section III. Staged test and operational data specifications

1. Section III applies when a staged test and/or operational data verification methodology is utilized. If utilizing multiple methodologies to verify the Facility capability, not all data points outlined in Section III, Item 6, 7, 8, or 9 need to be recorded.
2. Record any staged test or operational data in Attachment 3 (or a form containing the same information). If metering does not exist to measure specific values listed in Attachment 3, provide an engineering estimate and associated calculations. Refer to the associated labels depicted in the one-line diagram created in Section II, Item 4. Record any additional data deemed necessary to perform engineering analysis per Note 1.
3. Staged testing or operating conditions should be maintained constant for a sufficient time in order to ensure that the applicable Facility can perform at that level of Real and Reactive Power during steady-state conditions.
4. All auxiliary equipment is expected to be in service for normal operation.
5. The automatic voltage regulating equipment is in automatic voltage regulating mode.
6. For an applicable Facility with Real Power capability, record measurements at the following four points:

6.1. Maximum lagging Reactive Power at maximum Real Power until a limit is reached;[2]

6.2. Maximum leading Reactive Power at maximum Real Power until a limit is reached;

6.3. Maximum lagging Reactive Power at minimum Real Power until a limit is reached;

6.4. Maximum leading Reactive Power at minimum Real Power until a limit is reached.

7. For an applicable Facility with no Real Power capability, record measurements at the following two points (one over-excited point and one under-excited point):

7.1. Maximum lagging Reactive Power until a limit is reached;

7.2. Maximum leading Reactive Power until a limit is reached.

8. For an applicable Facility with equal minimum and maximum Real Power output during normal operation, such as a nuclear unit, record measurements at the two points in Items 8.1 and 8.2 below. The Facility need only perform staged testing or provide operational data for Reactive Power at maximum Real Power output. If applicable, provide the theoretical Reactive Power capability at minimum Real Power output in accordance with Attachment 2.

8.1. Maximum lagging Reactive Power at normal operating Real Power until a limit is reached;

8.2. Maximum leading Reactive Power at normal operating Real Power until a limit is reached.

9. For variable generating resources, such as wind, solar, or run-of-river hydro, and non-variable generating resources, such as battery energy storage systems, staged testing or operational data should be recorded with at least 90 percent of the inverters/generators at a Facility on-line. If staged testing or operational data capture of a Facility cannot be accomplished while meeting the 90 percent inverter/generator threshold, document the reason(s) the threshold was not met and test to the full available capability at the time of the test. Maintain, as steady as practical, the maximum Real Power output that the resource can provide at the time of the verification. Record measurements at the two points in Items 9.1 and 9.2 below at the maximum Real Power output the variable resource can provide at the time of the staged test or operational data.

9.1. Maximum lagging Reactive Power at normal operating Real Power until a limit is reached;

[2] In addition, consider steady state thermal or mechanical limitations of Facility equipment to determine whether it limits the Reactive Power capability during a staged test.

9.2. Maximum leading Reactive Power at normal operating Real Power until a limit is reached.

Note 1: Under restrictive transmission system conditions, the data points obtained from a staged test or operational data might not duplicate the manufacturer supplied thermal capability curve (D-curve). When the applicable Facility's reactive capability is not fully demonstrated, perform a simulation or engineering analysis to determine expected capability under less restrictive system voltages. Even though this analysis will not verify the complete thermal capability curve (D-curve), it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling.

MOD-025-3 Attachment 2 – BES Facility Capability Report

A completed report shall contain the following information at a minimum per Requirement R1 and R2:

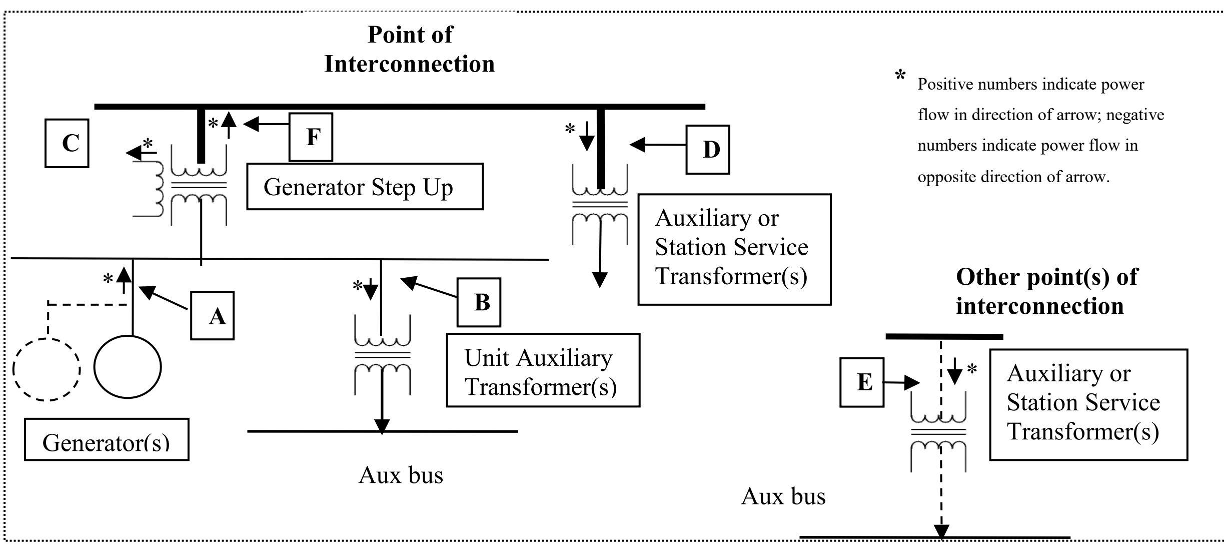
- Section I: One-line diagram of the applicable Facility
- Section II: Composite capability curve
- Section III: Associated PQ data table
- Section IV: Documentation showing the engineering basis and verification methodology

If the configuration of the applicable Facility does not lend itself to the use of the one-line diagram, capability curve, and data tables for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025-3, Attachment 1) is reported. An example report is provided below.

Company: **Reported By (name):**

Plant: **Unit No.:** **Date of Verification:**

Section I. Provide simplified one-line diagram of the applicable Facility showing plant auxiliary Load connections.



The composite capability curve provided below is applied at Point (XX) in the one-line diagram shown above.

Section II. Provide composite capability curve as defined in Attachment 1, Section II

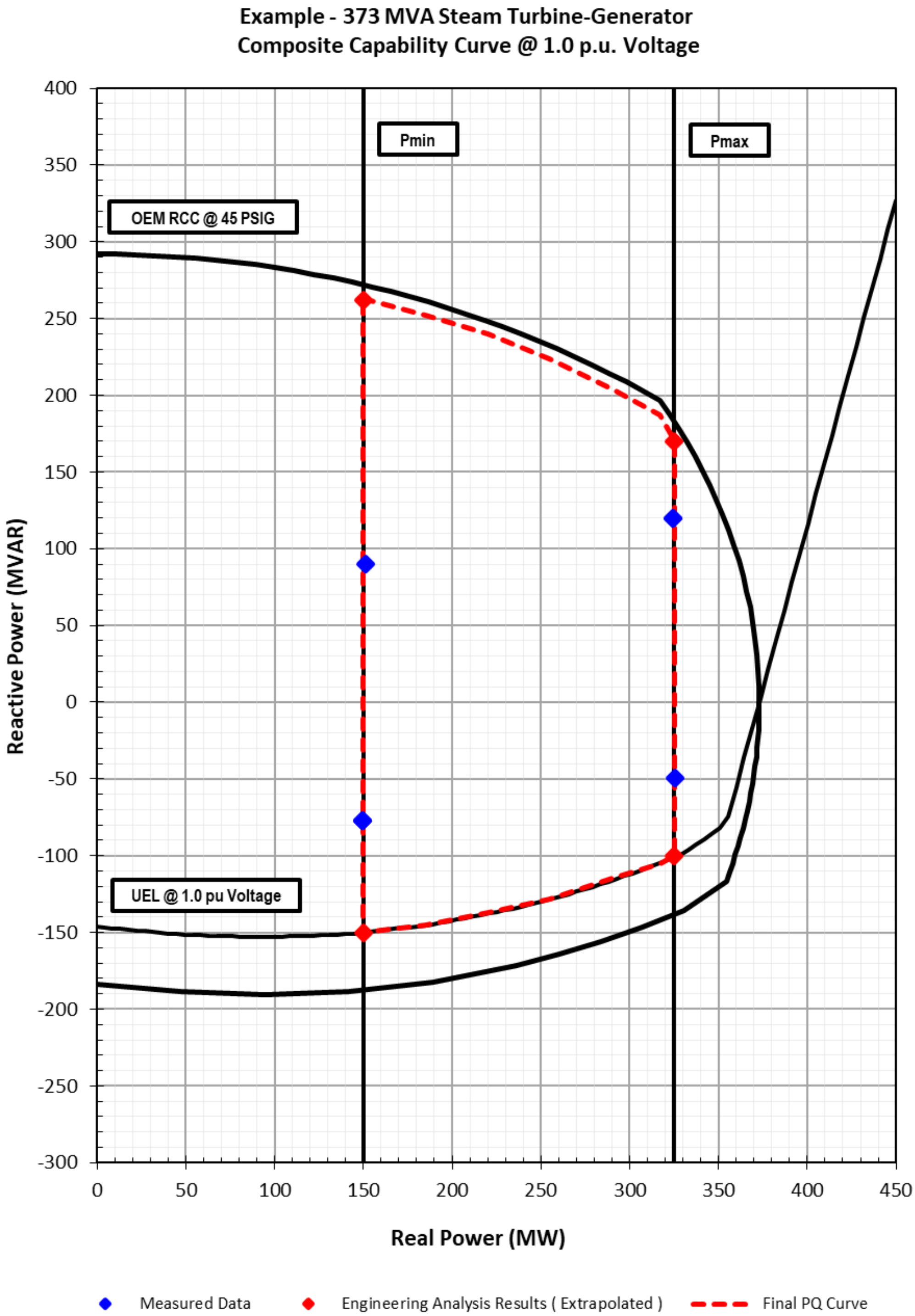


Figure 1.X: Example Composite Capability Curve for Synchronous Generator

Section III. Provided PQ curve data table associated with Figure 1.X composite capability curve

	P (MW)	Qmin (MVAr)	Qmax (MVAr)	Qmin Limit	Qmax Limit
Pmin	150.0	-150.0	263.0	UEL @ 1.0 Vterm	Ifd Rated
Pmin + 20% of range	185.0	-145.0	252.0	UEL @ 1.0 Vterm	Ifd Rated
Pmin + 40% of range	220.0	-137.0	240.0	UEL @ 1.0 Vterm	Ifd Rated
Pmin + 60% of range	255.0	-128.0	224.0	UEL @ 1.0 Vterm	Ifd Rated
Pmin + 80% of range	290.0	-115.0	204.0	UEL @ 1.0 Vterm	Ifd Rated
Breakpoint	317.1	-105.0	187.0	UEL @ 1.0 Vterm	Ifd Rated
Pmax	325.0	-100.0	170.0	UEL @ 1.0 Vterm	Ifd Rated

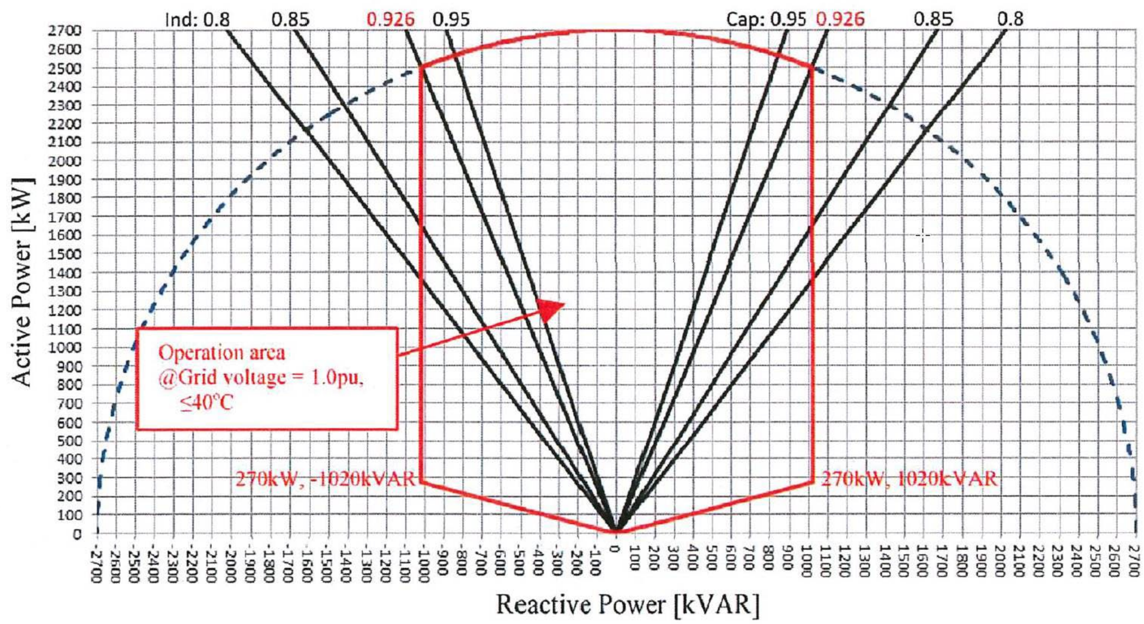


Figure 1.X: Example Composite Capability Curve for IBR Facility

PQ Curve Data Table (template)

Description	Pmax (MW)	Qmax (MVAR)	Qmin (MVAR)	Qmax Limiting Factor	Qmin Limiting Factor
P_{min}					
P_{min} + (0.20*Range)					

Range = (P_{max} - P_{min})					
P_{min} + (0.40*Range)					
P_{min} + (0.60*Range)					
P_{min} + (0.80*Range)					
P_{max}					
Additional data points such as breakpoints are optional.					

1. Limiting factor: UEL/OEL, field current rating, distributed control system (DCS) limit, etc.

Section IV. Supplemental documentation of engineering basis and verification methodology

MOD-025 Attachment 3

Data Table and Summary of Staged Test or Operational Data

Reference Attachment 2 one-line diagram measurement points and direction of flow arrows when recording Real and Reactive Power in data table. If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information is reported.

Company: **Reported By (name):**

Plant: **Unit No.:**

Check all that apply:

☐ Over-excited Maximum Load Reactive Power Verification

☐ Under-excited Maximum Load Reactive Power Verification

☐ Over-excited Minimum Load Reactive Power Verification

☐ Under-excited Minimum Load Reactive Power Verification

☐ Real Power Verification

☐ Staged Test Data

☐ Operational Data

Data Table for Recording Measurements

Point	Voltage	Real Power	Reactive Power	Comment
A	**kV**	**MW**	**Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B	**kV**	**MW**	**Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
C	**kV**	**MW**	**Mvar**	Sum multiple tertiary Loads, if any.
Identify calculated values, if any:				

D	**kV**	**MW**	**Mvar**	Sum multiple auxiliary and station service transformers.
Identify calculated values, if any:				
E	**kV**	**MW**	**Mvar**	If multiple points of Interconnection, describe these for accurate modeling; report points individually (sum multiple auxiliary transformers).
F	**kV**	**MW**	**Mvar**	Net unit capability
Identify calculated values, if any:				

<u>Summary of Test / Operational Data</u>

- Date of Staged Test (or oldest Date of Operational Data): _________
- Start Time _____, End Time ______, Staged Test or Operational Data ______
- Transformer Voltage Ratio: GSU ______, Unit Aux _____, Station Aux _____, Other Aux _____
- Transformer Tap Setting: GSU ______, Unit Aux _____, Station Aux _____, Other Aux _____
- Transformer Impedance: GSU ______; Transformer X/R ratio: GSU ______
- Generator or Exciter Field Current (synchronous only): Start _________, End ___________
- Ambient conditions at the end of the verification period:

  Air or inlet temperature: _________ Humidity: _________

  Cooling water temperature: _________ Stator temperature: ___________

  Other data as applicable: _________
- Generator cooling gas pressure at time of test (if applicable) _____________
- If the staged test/operational data did not reach capability curve (D-curve), describe the limiting factor.

<u>Testing Remarks:</u>

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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	March 4 – April 2, 2021

Anticipated Actions	Date
45-day formal or informal comment period with ballot	September – November 2022
45-day formal or informal comment period with additional ballot	February – April 2023
10-day final ballot	May 2023
Board adoption	August 2023

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:** Verification ~~and Data Reporting of Generator~~ of Real and Reactive Power Capability ~~and Synchronous Condenser Reactive Power Capability~~for BES Facilities

2. **Number:** ~~MOD-025-2~~MOD-025-3

3. **Purpose:** To ensure that accurate information on ~~generator gross and net~~ Bulk Electric System (BES) Facility Real and ~~Reactive Power capability and synchronous condenser~~ Reactive Power capability is available for planning models used to assess ~~Bulk Electric System (~~BES~~)~~ reliability.

4. **Applicability:**

   4.1. Functional ~~entities~~Entities:

   4.1.1 Generator Owner

   4.1.2 Transmission Owner ~~that owns synchronous condenser(s)~~

   4.1.3 Transmission Planner

   4.2. Facilities:

   For the purpose of this standard, the term, "applicable Facility" or "Facility" shall mean any one of the following:

   4.2.1 Individual generating ~~unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.~~resource identified through Inclusion I2 of the BES definition.

   ~~Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric **4.2.2**System.~~

   4.2.2 ~~**4.2.3**~~Generating plant/~~Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.~~Facility identified through Inclusion I2 of the BES definition.

   4.2.3 Generating plant/Facility of dispersed power producing resources identified through Inclusion I4 of the BES definition.

   4.2.4 Dynamic reactive devices identified through Inclusion I5 of the BES definition with a gross (individual or aggregate) nameplate rating greater than 20 MVA including, but not limited to:

   4.2.4.1 Synchronous condenser; and

   4.2.4.2 Flexible alternating current transmission system (FACTS) devices.

   4.2.5 HVDC terminal equipment including:

   4.2.5.1 Voltage source converter (VSC).

5. Effective Date: see Project 2021-01 Modifications to MOD-025 and PRC-019 Implementation Plan

~~**5.1.** In those jurisdictions where regulatory approval is required[1]:~~

~~**5.1.1** By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.~~

~~**5.1.2** By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.~~

~~**5.1.3** By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.~~

~~**5.1.4** By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.~~

~~**5.2.** In those jurisdictions where regulatory approval is not required[2]:~~

~~**5.2.1** By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.~~

~~**5.2.2** By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.~~

~~**5.2.3** By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.~~

~~[1] Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.~~

~~[2] Wind farm verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.~~

~~**5.2.4** By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.~~

B. ~~Note: The verification percentage above is based on the number of applicable units owned.~~Requirements and Measures

R1. Each Generator Owner shall ~~provide~~ verify the Real Power and Reactive Power capability of its applicable Facilities and inform its Transmission Planner ~~with verification of the Real Power capability of its applicable Facilities~~ as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Verify the Real Power capability~~-~~, if applicable, of its ~~generating units~~ applicable Facilities in accordance with Attachment 1.

1.2. ~~Submit a completed Attachment 2~~ Verify the Reactive Power capability ~~(or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.~~

~~**R2.** Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~

~~**2.1.** Verify,~~ of its applicable Facilities in accordance with Attachment 1~~, (i) the Reactive Power capability of its generating units and (ii) the Reactive Power capability of its synchronous condenser units.~~.

1.3. Submit the following information, in accordance with Attachment 2, to the Transmission Planner within 30 calendar days after the verification date:

1.3.1. One-line diagram representing the Facility;

1.3.2. Composite capability curve and associated PQ data table; and

1.3.3. Documentation showing the engineering basis, verification methodology and/or applicable data for the verification method.

~~**2.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.~~

~~**R3.** Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~

~~**3.1.** Verify, in accordance with Attachment 1, the Reactive Power capability of its synchronous condenser units.~~

~~**3.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.~~

~~B. Measures~~

M1. ~~Each Generator Owner will~~ Each Generator Owner shall have evidence that it ~~performed the verification, such as a completed Attachment 2 or the Generator Owner form with the same information or dated information collected and used to complete attachments, and will~~ verified Real Power and Reactive Power capability of each Facility, such as completed attachments or summary report(s); and have evidence that it submitted the information within ~~90~~ 30 calendar days after the verification date to its Transmission Planner~~; such as dated electronic mail messages or mail receipts~~ in accordance with Requirement R1.

R2. Each Transmission Owner shall verify the Real Power and Reactive Power capability of its applicable Facilities and inform its Transmission Planner as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Verify the Real Power capability, if applicable, of its applicable Facilities in accordance with Attachment 1.

2.2. Verify the Reactive Power capability of its applicable Facilities, in accordance with Attachment 1.

2.3. Submit the following information per Attachment 2 to the Transmission Planner within 30 calendar days after the verification date:

2.3.1. One-line diagram representing the Facility;

2.3.2. Composite capability curve and associated PQ data table; and

2.3.3. Documentation showing the engineering basis, verification methodology and/or applicable data for the verification method.

M2. ~~Each Generator Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Generator Owner form with the same information, or dated information collected and used to complete attachments and will~~ Each Transmission Owner shall have evidence that it verified Real Power and Reactive Power capability of each Facility, such as completed attachments or summary report(s); and have evidence that it submitted the information within ~~90~~ 30 calendar days after the verification date to its Transmission Planner~~; such as dated electronic mail messages or mail receipts~~ in accordance with Requirement R2.

~~Each Transmission Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Transmission Owner form with equivalent information or dated information collected and used to complete attachments, and will have evidence that it submitted the information within 90 days to its Transmission Planner; such as dated electronic mail messages or mail receipts~~

R3. ~~M3.~~Each Transmission Planner shall review the information submitted by each Generator Owner or Transmission Owner in accordance with Requirement R1, R2, or R4 and provide a written response within 90 calendar days containing one of the following: *[Violation Risk Factor: Lower*~~in accordance with Requirement R3.~~*] [Time Horizon: Long-term Planning]*

- Notification that the Transmission Planner has not identified any technical concerns with the Real and Reactive Power capability information submitted by the Generator Owner or Transmission Owner; or
- Notification that the Transmission Planner has identified a technical concern, including the basis for the technical concern.

M3. Each Transmission Planner shall have evidence, such as a summary of items reviewed and dated correspondence of the notification, that it reviewed the information submitted and provided notification to the Generator Owner or Transmission Owner within 90 calendar days in accordance with Requirement R3.

R4. Each Generator Owner or Transmission Owner receiving a notification of a technical concern under Requirement R3 shall provide a written response to its Transmission Planner within 90 calendar days containing one of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Updated capability information in accordance with Requirements R1 or R2;
- A mutually agreed upon plan with its Transmission Planner to update the capability information in accordance with Requirements R1 or R2; or
- Technical justification and supporting evidence for maintaining the existing capability information in accordance with Requirements R1 or R2.

M4. Each Generator Owner or Transmission Owner shall have evidence that it responded to the Transmission Planner within 90 calendar days in accordance with Requirement R4.

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.

~~The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.~~

~~1.2. Evidence Retention~~

1.0. Evidence Retention: The following evidence retention ~~periods~~ period(s) identify ~~a~~ 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 ~~compliance~~ 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 ~~Generator Owner and Transmission Owner~~ applicable entity shall ~~each~~ keep ~~the~~ 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 shall keep data or evidence of Requirement R1 since the most current verification for each applicable BES Facility.
- Each Transmission Owner shall keep data or evidence of Requirement R2 since the most current verification for each applicable BES Facility.
- Each Transmission Planner shall keep data or evidence of Requirement R3 for a rolling 12 month period.

~~Generator Owner or Transmission Owner is found noncompliant, it shall keep information related to the noncompliance until mitigation is complete or for the time specified above, whichever is longer.The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.~~

~~1.1. Compliance Monitoring and Assessment Processes~~

~~Compliance Audit~~

~~Self-Certification~~

~~Spot Checking~~

~~Compliance Investigation~~

~~Self-Reporting~~

~~Complaint~~

~~1.2. Additional Compliance Information~~

~~None~~

- ~~The Generator Owner shall retain the latest MOD-025 Attachment 2 and the data behind Attachment 2 or Generator Owner form with equivalent information and submittal evidence for Requirements R1 and R2,~~

~~Measures M1 and M2 for the time period since the last compliance audit.~~

- ~~The Transmission Owner shall retain the latest MOD-025 Attachment 2 and the data behind Attachment 2 or Transmission Owner form with equivalent information and submittal evidence for Requirement R3, Measure M3 for the time period since the last compliance audit.~~

- ~~If a~~ Each Generator Owner and Transmission Owner shall keep data or evidence of Requirement R4 for a rolling 12 month period.

1.1. 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.

~~2.~~Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	~~The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 90 calendar days, but within 120 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ The applicable entity provided all items in Requirement R1, but did so between 31 and 90 calendar days after the verification date. OR ~~The Generator Owner verified the Real Power capability, per Attachment 1~~	~~The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ ~~OR~~ ~~The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing more than 33 to 66 percent of the data.~~	~~The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ ~~OR~~ ~~The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing from 67 to 99 percent of the data.~~	~~The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 180 calendar days of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ ~~OR~~ ~~The Generator Owner~~ The applicable entity provided all items in Requirement R1, but did so greater than 270 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power, but failed to include the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~and submitted the data but was missing 1 to less than or equal to 33 percent of the data.~~ ~~OR~~ ~~The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months.~~ ~~OR~~ ~~The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3~~	~~OR~~ ~~The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months.~~ ~~OR~~ ~~The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar~~	~~OR~~ ~~The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months.~~ ~~OR~~ ~~The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar~~	information required in Requirement R1, Part 1.3.2. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 3, but did so in more than 138 calendar months. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but did so in more than 450 calendar days. OR The applicable entity failed to verify the Real and/or Reactive Power capability~~, per Attachment 1 of an applicable generating unit~~. ~~OR~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~(12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.~~ The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 3, but did so between 10 years (120 calendar months) and 126 calendar months. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but did so between 181 and 270 calendar days.	~~months but less than or equal to 14 calendar months.~~ The applicable entity provided all items in Requirement R1, but did so between 91 and 180 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power, but failed to include the information required in Requirement R1, Part 1.3.1. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 3, but did so between 127 and 132 calendar months. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but	~~months but less than or equal to 15 calendar months.~~ The applicable entity provided all items in Requirement R1, but did so between 181 and 270 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power, but failed to include the information required in Requirement R1, Part 1.3.3. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 3, but did so between 133 and 138 calendar months. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but	~~The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 75 calendar months.~~ ~~OR~~ ~~The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15 calendar months.~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		did so between 271 and 360 calendar days.	did so between 361 and 450 calendar days.	
~~R2~~R2.	~~The Generator Owner verified and recorded the Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 90 calendar days, but within 120 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ ~~OR~~ ~~The Generator Owner verified the~~ The applicable entity provided all items in Requirement R2, but did so between 31 and 90 calendar days after the verification date. OR	~~The Generator Owner verified and recorded the Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ ~~OR~~ ~~The Generator Owner verified the~~ The applicable entity provided all items in Requirement R2, but did so between 91 and 180 calendar days after the verification date. OR	~~The Generator Owner verified and recorded the Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ ~~OR~~ ~~The Generator Owner verified the~~ The applicable entity provided all items in Requirement R2, but did so between 181 and 270 calendar days after the verification date. OR	~~The Generator Owner verified and recorded the Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 180 calendar days of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ ~~OR~~ ~~The Generator Owner failed to verify the~~ The applicable entity provided all items in Requirement R2, but did so greater than 270 calendar days after the verification date. OR

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 3, but did between 10 years (120 calendar months) and 126 calendar months. OR The applicable entity verified the Real and Reactive Power capability~~,~~ per Attachment 1 ~~and submitted the data but was missing 1 to up to and including 33 percent of the data.~~Section 1 Item 2, 4, or 5, but did so between 181 and 270 calendar days. ~~OR~~ ~~The Generator Owner performed the Reactive~~	The applicable entity verified the Real and Reactive Power, but failed to include the information required in Requirement R2, Part 2.3.1. OR The applicable entity verified the Real and Reactive Power capability~~, per Attachment 1 and submitted the data but was missing 34 to 66 percent of the data.~~ per Attachment 1 Section 1 Item 3, but did so between 127 and 132 calendar months. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but did so between 271 and 360 calendar days. ~~OR~~	The applicable entity verified the Real and Reactive Power, but failed to include the information required in Requirement R2, Part 2.3.3. OR The applicable entity verified the Real and Reactive Power capability~~, per Attachment 1 and submitted the data but was missing 67 to 99 percent of the data.~~ per Attachment 1 Section 1 Item 3, but did so between 133 and 138 calendar months. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but did so between 361 and 450 calendar days. ~~OR~~ ~~The Generator Owner performed the Reactive~~	The applicable entity verified the Real and Reactive Power, but failed to include the information required in Requirement R2, Part 2.3.2. OR The applicable entity verified the Real and Reactive Power capability~~,~~ per Attachment 1 ~~of an applicable generating unit or synchronous condenser unit. OR The Generator Owner performed the Reactive Power verification per Attachment 1~~Section 1 Item 3, ~~"Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement)~~ but did so in more than ~~75~~ 138 calendar months. OR ~~The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months.~~ ~~OR~~ ~~The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.~~	~~The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months.~~ ~~OR~~ ~~The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.~~	~~Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months.~~ ~~OR~~ ~~The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.~~	~~for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15 calendar months.~~ The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but did so in more than 450 calendar days. OR The applicable entity failed to verify the Real and/or Reactive Power capability.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
~~R3~~R3.	The ~~Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its~~ Transmission Planner ~~more than 90 calendar days, but within 120 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~provided a written response to the submitter, but it was provided between 91 to 120 calendar days after receiving the verified model information. ~~OR~~ ~~The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 1 to up to and~~	~~The Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ ~~OR~~ ~~The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 34 to 66 percent of the data.~~ ~~OR~~	~~The Transmission Owner verified and recorded the Reactive Power capability of an applicable synchronous condenser unit, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ ~~OR~~ ~~The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 67 to 99 percent of the data.~~ ~~OR~~	~~The Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 180 calendar days of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ ~~OR~~ ~~The Transmission Owner failed to verify the Reactive Power capability, per Attachment 1 of an applicable synchronous condenser unit.~~ ~~OR~~ ~~The Transmission Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement)~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~including 33 percent of the data.~~ ~~OR~~ ~~The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months.~~ ~~OR~~ ~~The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar~~	~~The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months.~~ ~~OR~~ ~~The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.~~ The Transmission Planner provided a written response to the submitter, but it was	~~The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months.~~ ~~OR~~ ~~The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.~~ The Transmission Planner provided a written response to the submitter, but it was	~~but did so in more than 75 calendar months.~~ ~~OR~~ ~~The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15calendar months.~~ The Transmission Planner failed to provide a written response to the submitter. OR The Transmission Planner provided a written response to the submitter but it was provided more than 180 calendar days after receiving the verified model information.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~months but less than or equal to 13 calendar months.~~	provided between 121 to 150 calendar days after receiving the verified model information.	provided between 151 to 180 calendar days after receiving the verified model information.	
R4.	The applicable entity provided a written response to its Transmission Planner, but it was provided between 91 to 120 calendar days after receiving a notification of technical concern.	The applicable entity provided a written response to its Transmission Planner, but it was provided between 121 to 150 calendar days after receiving a notification of technical concern.	The applicable entity provided a written response to its Transmission Planner, but it was provided between 151 to 180 calendar days after receiving a notification of technical concern.	The applicable entity failed to provide a written response to its Transmission Planner. OR The applicable entity provided a written response to its Transmission Planner, but it was provided greater than 180 calendar days after receiving a notification of technical concern.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	12/1/2005	1. Changed tabs in footer. 2. Removed comma after 2004 in "Development Steps Completed," #1. 3. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 4. Added "periods" to items where appropriate. 5. Changed apostrophes to "smart" symbols. 6. Changed "Timeframe" to "Time Frame" in item D, 1.2. 7. Lower cased all instances of "regional" in section D.3. 8. Removed the word "less" after 94% in section 3.4. Level 4.	01/20/06
2	February 7, 2013	Adopted by NERC Board of Trustees	Revised per SAR for Project 2007-09 and combined with MOD-024-1
2	March 20, 2014	FERC Order issued approving MOD-025-2. (Order becomes effective on 7/1/16.)	
3	Month XX, 2022	Adopted by NERC Board of Trustees	Revised per SAR for Project 2021-01

MOD-025-3 Attachments

~~MOD-025~~ MOD-025-3 Attachment 1 – Verification of ~~Generator~~ Real and ~~Reactive Power Capability and Synchronous Condenser~~ Reactive Power Capability for BES Facilities

Section I. Periodicity ~~for conducting a new~~ of verification:

The periodicity ~~for performing~~ to verify the Real and Reactive Power capability ~~verification~~ for each applicable BES Facility is as follows:

1. The applicable entity designates the verification date and notates the verification date in a summary report (refer to Attachment 2). The verification date should represent the date that the engineering review or engineering analysis is complete. The verification date is the basis of the recurring periodicity.
2. Verify each new applicable Facility within 180 calendar days of its commercial operation date.
3. Verify each existing applicable Facility at a periodicity not to exceed ten years from the last verification date.
4. ~~1.For staged verification; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months~~ Verify an existing applicable Facility within 180 calendar days of the discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent ~~of the last reported verified capability~~ increase or decrease of the nameplate rating and is expected to last more than ~~six months. The first verification for each applicable Facility under this standard must be a staged test.~~180 calendar days.
5. Verify an existing applicable Facility within 180 calendar days of its return to service date, if the Facility has a planned or unplanned outage of 180 days or more which overlaps its scheduled verification date and has not had its capability verified within the past ten years.

~~2. For verification using operational data; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months following the discovery that its Real Power or Reactive Power capability has changed by more than 10 percent of the last reported verified capability and is expected to last more than six months. If data for different points is recorded on different days, designate the earliest of those dates as the verification date, and report that date as the verification date on MOD-025, Attachment 2 for periodicity purposes.~~

~~3. For either verification method, verify each new applicable Facility within 12 calendar months of its commercial operation date. Existing units that have been in long term shut~~

~~down and have not been tested for more than five years shall be verified within 12 calendar months.~~

~~It is intended that Real Power testing be performed at the same time as full load Reactive Power testing, however separate testing is allowed for this standard. For synchronous condensers, perform only the Reactive Power capability verifications as specified below.~~

~~If the Reactive Power capability is verified through test, it is to be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measures to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value.~~

Section II. Verification specifications for applicable Facilities:

1. ~~For generating units of 20 MVA or less that are part of a plant greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group. Perform verification individually for every generating unit or synchronous condenser~~ For individual devices or generators greater than 20 MVA (gross nameplate rating) ~~.~~perform verification on an individual basis.

   ~~2.2. Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions:~~

      ~~2.2.1 At the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached.~~

      ~~2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached.~~

      ~~2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output.~~

   ~~2.3. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure.~~

   ~~2.4. Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.~~

~~3. Record the following data for the verifications specified above:~~

   ~~3.1. The value of the gross Real and Reactive Power generating capabilities at the end of the verification period.~~

   ~~3.2. The voltage schedule provided by the Transmission Operator, if applicable.~~

~~2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification. Perform verification~~

~~with the automatic voltage regulator in service for the Reactive Power capability verification. Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as a) that operational data meets the criteria in 2.1 through 2.4 below and b) the operational data demonstrates at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted (so that it did not demonstrate at least 50 percent of the associated thermal capability curve) by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification will be by another staged test, not operational data:~~

~~**2.1.** Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications.~~

~~**2.1.1** Verify synchronous generating unit's maximum real power and lagging reactive power for a minimum of one hour.~~

2. ~~**2.1.2**Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter~~ For individual devices or generators ~~Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications.~~ 20 MVA (gross nameplate rating) or less that are part of an applicable Facility greater than 75 MVA (gross nameplate rating) in aggregate, perform verification on an individual unit basis or in the aggregate, considering applicable modeling expectations of the respective Transmission Planner.

3. Create a simplified key one-line diagram representing the Facility (refer to Attachment 2). The one-line diagram shall designate where the composite capability curve created in Section II, Items 6-8 is represented.

   3.1. ~~**3.3.**The voltage at the high and low side of the GSU~~ The one-line representing the Facility shall include all auxiliary equipment expected to be in-service for normal operation, including dynamic and static reactive devices and auxiliary load, the GSU, and/or system interconnection transformer(s)~~at the end of the verification period. If only one of these values is metered, the other may be calculated.~~, unit auxiliary transformer(s), and station services auxiliary transformer(s).

4. If an applicable Facility has no leading or lagging capability, then it should be reported with no leading or lagging capability.

5. The Generator Owner or Transmission Owner shall utilize and document one or more of the following methodologies to verify the Facility capability for all equipment expected to be in-service for normal operation. The engineering review or engineering analysis shall include underlying assumptions, design criteria, and methods used to create the Facility capability curve under Section II, Items 6-8.

   - Perform an engineering review of all Real and Reactive Power Facility capability information including but not limited to in-service equipment design limitations, excitation limiter settings, and operational limitations;
   - Utilize staged testing data, in accordance with Section III, obtained from a date within 365 calendar days prior to verification date, and perform engineering analysis as needed per Note 1, that validates the generator capability; or
   - Utilize operational data, in accordance with Section III, obtained from a date within 365 calendar days prior to verification date, and perform engineering analysis as needed per Note 1, that validates the generator capability.

6. For an applicable Facility as identified in Section 4.2.1, 4.2.2, or 4.2.4.1, when performing verification on an individual unit basis, create a graphical representation of the steady-state composite capability curve (CCC) for the Real Power and Reactive Power. The steady-state CCC shall include at a minimum the following:

   6.1. The generator steady-state Real Power and Reactive Power capability curve, or the synchronous condenser steady-state Reactive Power capability curve, provided by the equipment manufacturer.

      6.1.1 The curve shall represent generator/synchronous condenser capability at a nominal voltage of 1.0 per unit at the generator/synchronous condenser terminal; and

      6.1.2 The curve shall notate the operating conditions that dictate the power capability, for example H2 pressure, ambient temperature, or other conditions.

   6.2. Excitation limiters, if more restrictive than the equipment manufacturer's capability curve, at nominal voltage 1.0 per unit;

   6.3. Identification of any Real Power or Reactive Power operational limitations[1], if applicable;

[1] Such as generator cooling, vibration, de-rated rotor, de-rated GSU transformer, generator bus de-rating, software limitations, or distributed control system (DCS) setpoints (outer-loop control system paths). This excludes fuel availability, such as water levels for hydro, cloud cover for PV, wind speed, or river level for run of river.

6.4. Identification of the steady-state minimum (P_{min}) and maximum (P_{max}) Real Power output at the generator terminal(s), based on the least restrictive seasonal or operating conditions; and

6.5. Identification of final PQ curve, which defines the normal operating region.

7. For an applicable Facility as identified in Section 4.2.2 or Section 4.2.3, when performing verification in aggregate, create a graphical representation of the steady-state composite capability curve (CCC) for the Real Power and Reactive Power. The steady-state CCC shall include at a minimum the following:

7.1. The steady-state Real and Reactive Power capability curve represented as an aggregate.

7.1.1 The curve shall represent Facility capability at a steady-state nominal voltage of 1.0 per unit at the common point of connection; and

7.1.2 The curve shall notate the operating conditions that dictate the power capability, for example H2 pressure, ambient temperature, or other conditions.

7.2. Aggregate Facility capability includes all auxiliary equipment expected to be in-service for normal operation, including dynamic and static reactive resources and auxiliary loads;

7.3. Identification of any Real Power or Reactive Power operational limitations, if applicable;

7.4. For inverter based resources, a description of all power plant controller and inverter control functions during normal operating conditions that dictate the aggregate Facility capability;

7.5. Identification of the steady-state minimum (P_{min}) and maximum (P_{max}) Real Power output at the common point of connection, based on the least restrictive seasonal or operating conditions; and

7.6. Identification of final PQ curve, which defines the normal operating region.

8. For an applicable Facility as identified in Section 4.2.4.2 and Section 4.2.5.1, create a graphical representation of the steady-state composite capability curve (CCC) for the Real Power and Reactive Power. The steady-state CCC shall include at a minimum the following:

8.1. The HVDC steady-state Real Power and Reactive Power capability curve, or the FACTS device steady-state Reactive Power capability, provided by the equipment manufacturer.

8.1.1 The curve shall represent Facility capability at a steady-state nominal voltage of 1.0 per unit at the common point of connection ; and

8.1.2 The curve shall notate the operating conditions that dictate the power capability, for example ambient temperature or other conditions.

8.2. Any limiters, if more restrictive than the equipment manufacturer's capability curve(s), at nominal voltage 1.0 per unit;

8.3. Identification of any Real Power or Reactive Power operational limitations, if applicable;

8.4. A description of all control functions during normal operating conditions and a description of any Facility overload capabilities that dictate the aggregate Facility capability;

8.5. Identification of the steady-state minimum (P_{min}) and maximum (P_{max}) Real Power output at the common point of connection, based on the least restrictive seasonal or operating conditions; and

8.6. Identification of final PQ curve, which defines the normal operating region.

Section III. Staged test and operational data specifications

1. Section III applies when a staged test and/or operational data verification methodology is utilized. If utilizing multiple methodologies to verify the Facility capability, not all data points outlined in Section III, Item 6, 7, 8, or 9 need to be recorded.

~~3.4. The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:~~

- ~~Ambient air temperature~~
- ~~Relative humidity~~
- ~~Cooling water temperature~~
- ~~Other data as determined to be applicable by the Generator Owner to perform corrections for ambient conditions.~~

~~3.5. The date and time of the verification period, including start and end time in hours and minutes.~~

~~3.6. The existing GSU and/or system interconnection transformer(s) voltage ratio and tap setting.~~

~~3.7. The GSU transformer losses (real or reactive) if the verification measurements were taken from the high side of the GSU transformer.~~

~~3.8. Whether the test data is a result of a staged test or if it is operational data.~~

~~4. Develop a simplified key one-line diagram (refer to MOD-025, Attachment 2) showing sources of auxiliary Real and Reactive Power and associated system connections for~~

~~each unit verified. Include GSU and/or system Interconnection and auxiliary transformers. Show Reactive Power flows, with directional arrows.~~

2. ~~4.1.If metering does not exist to measure specific Reactive auxiliary load(s)~~Record any staged test or operational data in Attachment 3 (or a form containing the same information). If metering does not exist to measure specific values listed in Attachment 3, provide an engineering estimate and associated calculations. ~~Transformer Real and Reactive Power losses will also be estimates or calculations. Only output data are required when using a computer program to calculate losses or loads.~~ Refer to the associated labels depicted in the one-line diagram created in Section II, Item 4. Record any additional data deemed necessary to perform engineering analysis per Note 1.

3. Staged testing or operating conditions should be maintained constant for a sufficient time in order to ensure that the applicable Facility can perform at that level of Real and Reactive Power during steady-state conditions.

4. All auxiliary equipment is expected to be in service for normal operation.

5. The automatic voltage regulating equipment is in automatic voltage regulating mode.

6. For an applicable Facility with Real Power capability, record measurements at the following four points:

   6.1. Maximum lagging Reactive Power at maximum Real Power until a limit is reached;[2]

   6.2. Maximum leading Reactive Power at maximum Real Power until a limit is reached;

   6.3. Maximum lagging Reactive Power at minimum Real Power until a limit is reached;

   6.4. Maximum leading Reactive Power at minimum Real Power until a limit is reached.

7. For an applicable Facility with no Real Power capability, record measurements at the following two points (one over-excited point and one under-excited point):

   7.1. Maximum lagging Reactive Power until a limit is reached;

   7.2. Maximum leading Reactive Power until a limit is reached.

8. For an applicable Facility with equal minimum and maximum Real Power output during normal operation, such as a nuclear unit, record measurements at the two points in Items 8.1 and 8.2 below. The Facility need only perform staged testing or provide operational data for Reactive Power at maximum Real Power output. If

[2] In addition, consider steady state thermal or mechanical limitations of Facility equipment to determine whether it limits the Reactive Power capability during a staged test.

applicable, provide the theoretical Reactive Power capability at minimum Real Power output in accordance with Attachment 2.

8.1. Maximum lagging Reactive Power at normal operating Real Power until a limit is reached;

8.2. Maximum leading Reactive Power at normal operating Real Power until a limit is reached.

9. For variable generating resources, such as wind, solar, or run-of-river hydro, and non-variable generating resources, such as battery energy storage systems, staged testing or operational data should be recorded with at least 90 percent of the inverters/generators at a Facility on-line. If staged testing or operational data capture of a Facility cannot be accomplished while meeting the 90 percent inverter/generator threshold, document the reason(s) the threshold was not met and test to the full available capability at the time of the test. Maintain, as steady as practical, Real Power output at the maximum that the resource can provide at the time of the verification verifications. Record measurements at the two points in Items 9.1 and 9.2 below at the maximum Real Power output the variable resource can provide at the time of the staged test or operational data.

9.1. Maximum lagging Reactive Power at normal operating Real Power until a limit is reached;

9.2. Maximum leading Reactive Power at normal operating Real Power until a limit is reached.

~~5. If an adjustment is requested by the Transmission Planner, then develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator can be determined at different conditions, such as peak summer conditions. Adjust MW values tested to the ambient conditions specified by the Transmission Planner upon request and submit them to the Transmission Planner within 90 days of the request or the date the data was recorded/selected whichever is later.~~

~~Note 1: Under some transmission system conditions, the data points obtained by the Mvar verification required by the standard will not duplicate the manufacturer supplied thermal capability curve (D-curve). However, the verification required by the standard, even when conducted under these transmission system conditions, may uncover applicable Facility limitations; such as rotor thermal instability, improper tap settings or voltage ratios, inaccurate AVR operation, etc., which could be further analyzed for resolution. The Mvar limit level(s) achieved during a staged test or from operational data may not be representative of the unit's reactive capability for extreme system conditions. See Note 2.~~

~~Note 2:While not required by the standard, it is desirable to perform engineering analyses~~ Note 1: Under restrictive transmission system conditions, the data points obtained from a staged test or operational data might not duplicate the manufacturer supplied thermal capability curve (D-curve). When the applicable Facility's reactive capability is not fully demonstrated, perform a simulation or engineering analysis to determine expected ~~applicable Facility capabilities~~ capability under less restrictive system voltages ~~than those encountered during the verification~~. Even though this analysis will not verify the complete thermal capability curve (D-curve), it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling.

~~Note 3: The Reactive Power verification is intended to define the limits of the unit's Reactive Power capabilities. If a unit has no leading capability, then it should be reported with no leading capability; or the minimum lagging capability at which it can operate.~~

~~Note 4: Synchronous Condensers only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output.~~

~~**MOD-025 Attachment 2**~~

MOD-025-3 Attachment 2 – BES Facility Capability Report

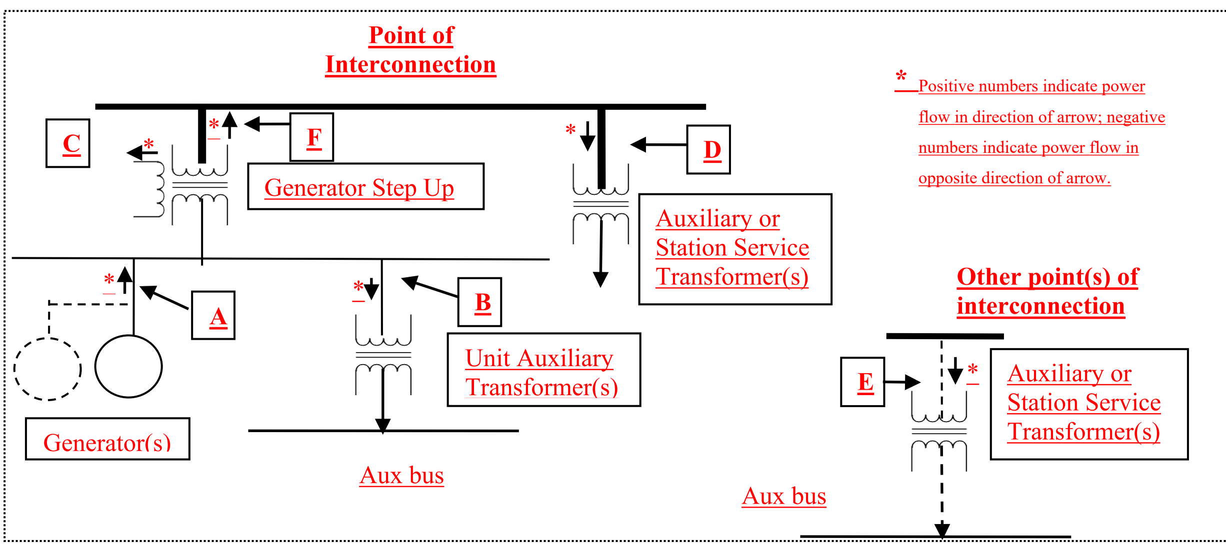
A completed report shall contain the following information at a minimum per Requirement R1 and R2:

- Section I: One-line diagram of the applicable Facility
- Section II: Composite capability curve
- Section III: Associated PQ data table
- Section IV: Documentation showing the engineering basis and verification methodology

If the configuration of the applicable Facility does not lend itself to the use of the one-line diagram, capability curve, and data tables for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025-3, Attachment 1) is reported. An example report is provided below.

Company:	**Reported By (name):**	
Plant:	**Unit No.:**	**Date of Verification:**

Section I. Provide simplified one-line diagram of the applicable Facility showing plant auxiliary Load connections.



The composite capability curve provided below is applied at Point (XX) in the one-line diagram shown above.

Section II. Provide composite capability curve as defined in Attachment 1, Section II

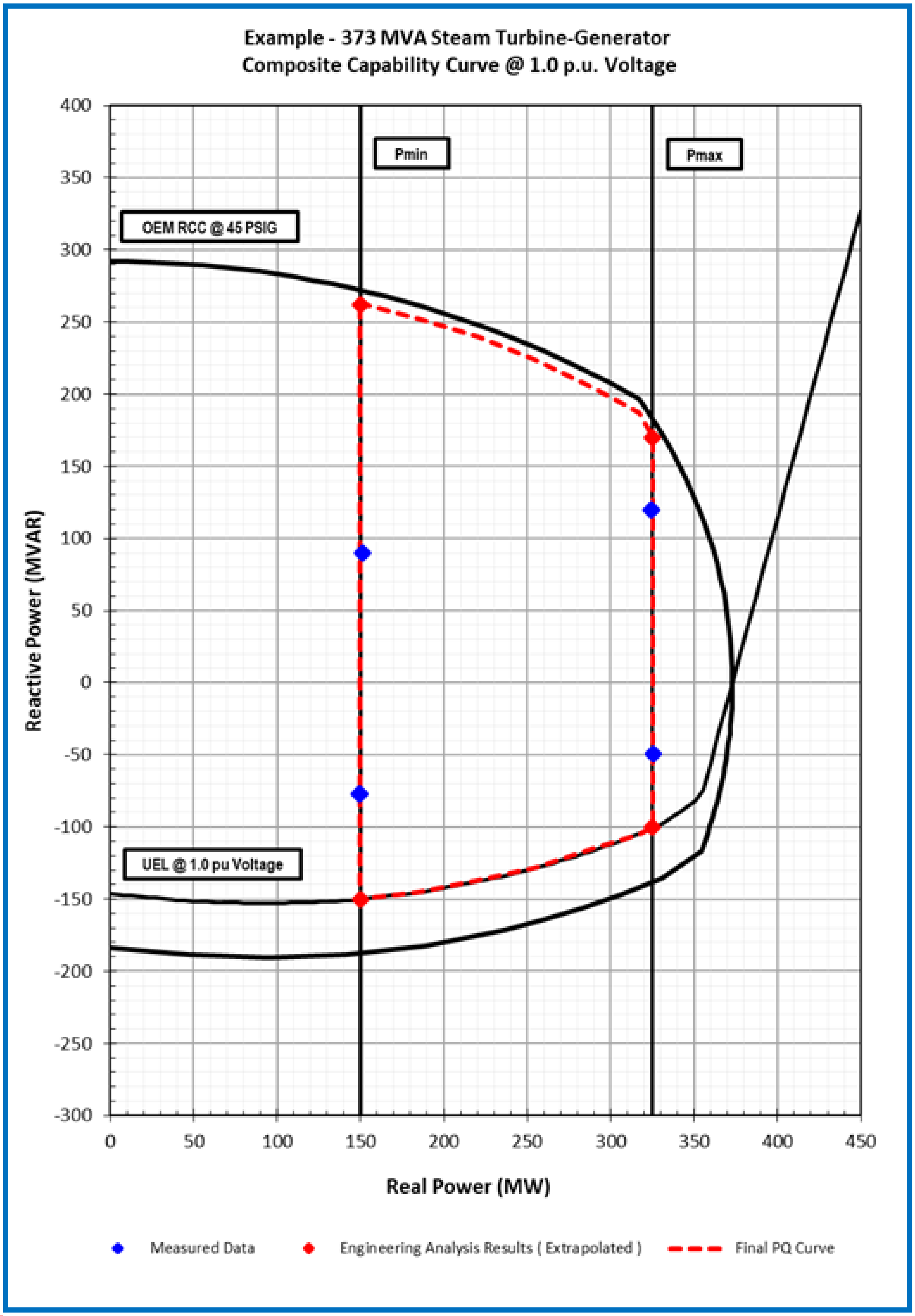


Figure 1.X: Example Composite Capability Curve for Synchronous Generator

Section III. Provided PQ curve data table associated with Figure 1.X composite capability curve

	P (MW)	Qmin (MVAr)	Qmax (MVAr)	Qmin Limit	Qmax Limit
Pmin	150.0	-150.0	263.0	UEL @ 1.0 Vterm	Ifd Rated
Pmin + 20% of range	185.0	-145.0	252.0	UEL @ 1.0 Vterm	Ifd Rated
Pmin + 40% of range	220.0	-137.0	240.0	UEL @ 1.0 Vterm	Ifd Rated
Pmin + 60% of range	255.0	-128.0	224.0	UEL @ 1.0 Vterm	Ifd Rated
Pmin + 80% of range	290.0	-115.0	204.0	UEL @ 1.0 Vterm	Ifd Rated
Breakpoint	317.1	-105.0	187.0	UEL @ 1.0 Vterm	Ifd Rated
Pmax	325.0	-100.0	170.0	UEL @ 1.0 Vterm	Ifd Rated

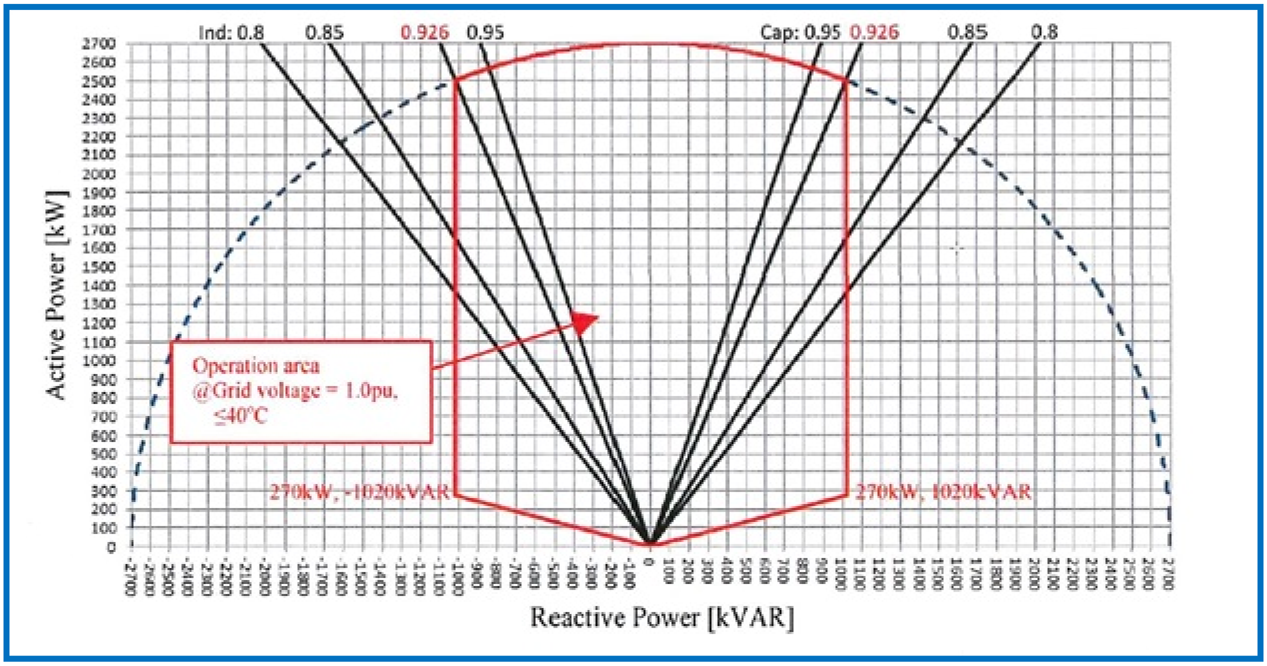


Figure 1.X: Example Composite Capability Curve for IBR Facility

PQ Curve Data Table (template)

Description	Pmax (MW)	Qmax (MVAR)	Qmin (MVAR)	Qmax Limiting Factor	Qmin Limiting Factor

P_{min}					
P_{min} + (0.20*Range) Range = (P_{max} - P_{min})					
P_{min} + (0.40*Range)					
P_{min} + (0.60*Range)					
P_{min} + (0.80*Range)					
P_{max}					
Additional data points such as breakpoints are optional.					

1. Limiting factor: UEL/OEL, field current rating, distributed control system (DCS) limit, etc.

Section IV. Supplemental documentation of engineering basis and verification methodology

MOD-025 Attachment 3

~~One-line Diagram, Table,~~ Data Table and Summary ~~for Verification Information Reporting~~of Staged Test or Operational Data

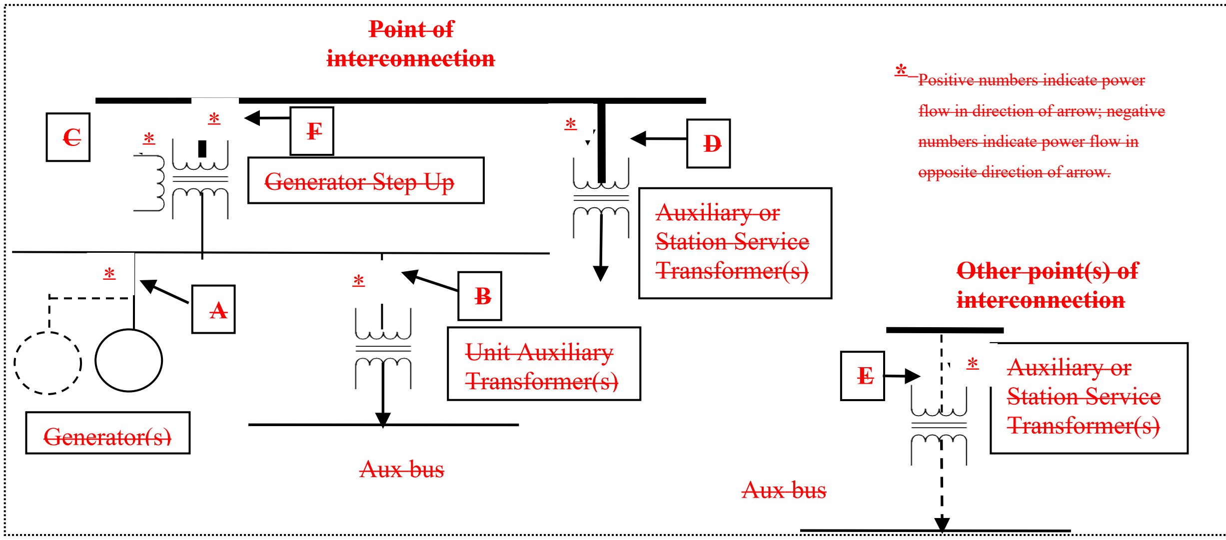
~~Note:~~Reference Attachment 2 one-line diagram measurement points and direction of flow arrows when recording Real and Reactive Power in data table. If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information ~~(identified in MOD-025, Attachment 1)~~ is reported.

Company:	**Reported By (name):**
Plant:	**Unit No.:** ~~**Date of Report:**~~

Check all that apply:

- ☐ Over-excited ~~Full~~ Maximum Load Reactive Power Verification
- ☐ Under-excited ~~Full~~ Maximum Load Reactive Power Verification
- ☐ Over-excited Minimum Load Reactive Power Verification
- ☐ Under-excited Minimum Load Reactive Power Verification
- ☐ Real Power Verification
- ☐ Staged Test Data
- ☐ Operational Data

~~Simplified one-line diagram showing plant auxiliary Load connections and verification data:~~



Data Table for Recording Measurements

Point	Voltage	Real Power	Reactive Power	Comment
A	kV	MW	Mvar	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B	kV	MW	Mvar	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
C	kV	MW	Mvar	Sum multiple tertiary Loads, if any.
Identify calculated values, if any:				
D	kV	MW	Mvar	Sum multiple auxiliary and station service transformers.
Identify calculated values, if any:				
E	kV	MW	Mvar	If multiple points of Interconnection, describe these for accurate modeling; report points individually (sum multiple auxiliary transformers).
F	kV	MW	Mvar	Net unit capability
Identify calculated values, if any:				

~~MOD-025 -Attachment 2 (continued)~~

~~Verification Data~~

~~Provide data by unit or Facility, as appropriate~~

~~Data Type~~	~~Data Recorded~~	~~Last Verification~~ ~~(Previous Data; will be blank for the initial verification)~~
~~Gross Reactive Power Capability (*Mvar)~~		
~~Aux Reactive Power (*Mvar)~~		
~~Net Reactive Power Capability (*Mvar) equals Gross Reactive Power Capability (*Mvar) minus Aux Reactive Power connected at the same bus (*Mvar) minus tertiary Reactive Power connected at the same bus(*Mvar)~~		
~~Gross Real Power Capability (*MW)~~		
~~Aux Real Power (*MW)~~		
~~Net Real Power Capability (*MW) equals Gross Real Power Capability (*MW) minus Aux Real Power connected at the same bus (*MW) minus tertiary Real Power connected at the same bus(*MW)~~		

~~* Note: Enter values at the end of the verification period.~~

~~GSU losses (only required if verification measurements are taken on the high side of the GSU - Mvar)~~		

Summary of ~~Verification~~Test / Operational Data

- Date of Staged Test (or oldest Date of Operational Data): ___________
- ~~Date of Verification~~ ___________, ~~Verification~~ Start Time _____, ~~Verification~~ End Time ______, Staged Test or Operational Data _______
- ~~Scheduled Voltage~~ _______________
- Transformer Voltage Ratio: GSU ______, Unit Aux _____, Station Aux _____, Other Aux _____
- Transformer Tap Setting: GSU ______, Unit Aux _____, Station Aux _____, Other Aux _____
- Transformer Impedance: GSU ________; Transformer X/R ratio: GSU ________
- Generator or Exciter Field Current (synchronous only): Start ___________, End ____________

- Ambient conditions at the end of the verification period:

  Air or inlet temperature: __________ Humidity: __________

  Cooling water temperature: __________ ________Stator temperature: ____________

  Other data as applicable: __________

- Generator ~~hydrogen~~ cooling gas pressure at time of test (if applicable) ______________

~~Date that data shown in last verification column in table above was taken~~ ______________

~~Remarks :~~

- ~~Note:~~ If the ~~verification value~~ staged test/operational data did not reach ~~the thermal~~ capability curve (D-curve), describe the ~~reason~~limiting factor.

Testing Remarks:

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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	March 4 – April 2, 2021

Anticipated Actions	Date
45-day formal or informal comment period with ballot	September – November 2022
45-day formal or informal comment period with additional ballot	February – April 2023
10-day final ballot	May 2023
Board adoption	August 2023

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:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection
2. **Number:** PRC-019-3
3. **Purpose:** To verify coordination of generating unit or Facility voltage regulating controls, limit functions, equipment capabilities, and protective functions.
4. **Applicability:**

4.1. Functional Entities

4.1.1 Generator Owner

4.1.2 Transmission Owner

4.2. Facilities

For the purpose of this standard, the term, "applicable Facility" or "Facility" shall mean any one of the following:

4.2.1 Individual generating resource identified through Inclusion I2 of the BES definition.

4.2.2 Generating plant/Facility identified through Inclusion I2 of the BES definition.

4.2.3 Dynamic reactive resources identified through Inclusion I5 of the BES definition with a gross (individual or aggregate) nameplate rating greater than 20 MVA including:

4.2.3.1 Synchronous condenser.

4.2.4 Inverter-based resource (IBR) generating plant/Facility identified through Inclusion I4 of the BES definition, including:

4.2.4.1 Individual IBR units;

4.2.4.2 Collector bus(es) and collector feeder(s);

4.2.4.3 Static or dynamic reactive compensating devices;

4.2.4.4 Main power transformer (MPT);[1]

[1] 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.

4.2.4.5 Generator step-up (GSU) transformer(s);[2]

4.2.5 Any Blackstart Resource.

5. Effective Date:

See the Implementation Plan for PRC-019-3.

B. Requirements and Measures

R1. At a maximum of every six calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate[3] the voltage regulating system controls, with the applicable equipment capabilities and settings of the applicable protective functions.[4] Equipment capabilities, control functions, and protective functions for the applicable Facilities include, but are not limited to those listed in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. For synchronous generators or synchronous condensers, assuming the normal automatic voltage regulator control loop and steady-state system operating conditions, verify the following coordination items:

1.1.1. The in-service limiter functions[5] are set to operate before the protective functions of the applicable Facility in order to avoid disconnecting the generator unnecessarily.

1.1.2. The applicable in-service protective functions are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities.

1.2. For IBR generating Facilities, assuming the voltage control mode is enabled in the power plant controller and/or IBR unit(s)[6] and steady-state system operating conditions, verify the following coordination items:

---

[2] For the purpose of this standard, the GSU is the power transformer that steps up voltage from the individual IBR unit to the nominal collection system voltage for dispersed power producing resources.

[3] As-left settings shall be utilized in a protection and control coordination study.

[4] A protective function includes an action performed by a Protection System device or an action performed by a control system that replicates the behavior of a Protection System device in order to mitigate the consequences of an event that exceeds equipment design basis.

[5] Limiter functions that are installed and activated on the generator or synchronous condenser.

[6] IBR unit includes the inverter, converter, or wind turbine generator.

1.2.1. The in-service control functions of the power plant controller are set to operate before the protective functions of the applicable Facilities in order to avoid disconnecting any of the Facilities listed under Section 4.2.4 unnecessarily.

1.2.2. The in-service control functions of IBR unit(s) are set to operate before protective functions of the applicable Facilities in order to avoid disconnecting any of Facilities listed under Section 4.2.4 unnecessarily.

1.2.3. The applicable in-service protective functions are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities.

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence such as a graphical representation(s) of coordination including a P-Q Diagram, R-X Diagram, Inverse Time Diagram, equivalent tables, steady-state calculations, dynamic simulation studies, or other evidence that it performed a coordination study as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

R2. Each Generator Owner and Transmission Owner shall perform the coordination described in Requirement R1 prior to implementation of systems, equipment, or settings changes that will affect the coordination described in Requirement R1; and update associated coordination documentation within 90 calendar days after the return to in-service date. These possible systems, equipment or settings changes include, but are not limited to, the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Voltage regulating settings or equipment changes;
- Protective function settings or component changes;
- IBR unit, synchronous generator or synchronous condenser equipment capability changes;
- IBR unit, synchronous generator or synchronous condenser step-up transformer changes;
- IBR unit control system firmware or settings changes; or
- Power plant controller firmware or settings changes.

M2. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence of the coordination study required by the events listed in Requirement R2. This evidence should include dated documentation that demonstrates Requirement R2 has been met.

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 Requirement R1 of the most recent coordination study.
   - The Generator Owner and Transmission Owner shall keep data or evidence of Requirement R2 of the most recent coordination study.

   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.	The Generator Owner or Transmission Owner coordinated equipment capabilities, control functions, and protection specified in Requirement R1 between 6 years (72 months) and 76 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, control functions, and protection specified in Requirement R1 between 77 and 81 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, control functions, and protection specified in Requirement R1 between 82 and 86 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, control functions, and protection specified in Requirement R1 more than 86 months after the previous coordination. OR The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection as specified in Requirement R1.
R2.	The Generator Owner or Transmission Owner updated associated coordination documentation as specified in Requirement R2 between 91 and 120 calendar days after return to in-service date.	The Generator Owner or Transmission Owner updated associated coordination documentation as specified in Requirement R2 between 121 and 150 calendar days after return to in-service date.	The Generator Owner or Transmission Owner updated associated coordination documentation as specified in Requirement R2 between 151 and 180 calendar days after return to in-service date.	The Generator Owner or Transmission Owner failed to update associated coordination documentation as specified in Requirement R2 within 151 calendar days after return to in-service date. OR The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 prior

				to the implementing a change in equipment or settings that affected the coordination.

D. Regional Variances

None.

E. Associated Documents

“Underexcited Operation of Turbo Generators”, AIEE Proceedings T Section 881, Volume 67, 1948, Appendix 1, C. G. Adams and J. B. McClure.

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

“Coordination of Generator Protection with Generator Excitation Control and Generator Capability”, a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee

“IEEE C37.102-2006 IEEE Guide for AC Generator Protection”

“IEEE C50.13-2005 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above”

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

Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New
1	March 20, 2014	FERC Order issued approving PRC-019-1. (Order becomes effective on 7/1/16.)	
2	February 12, 2015	Adopted by 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-019-2	Modifications to adjust the applicability to owners of dispersed generation resources.
3	*Date*	Adopted by NERC Board of Trustees	Standard revised in Project 2021-01

Attachment 1: Equipment Capabilities, Types of Limiters, and Protective Functions

NOTE: This standard does not require the installation or activation of any of the limiter or protection functions for synchronous generation or IBR.

A. Synchronous generation equipment capabilities, control functions, and protective functions, which shall be coordinated if enabled, include but are not limited to:

- Synchronous generator/condenser reactive capabilities;
- Field over-excitation limiter and associated protective function;
- Field under-excitation limiter and associated protective function;
- Volts per hertz limiter and associated protective function;
- Stator over-voltage protection system settings;
- Synchronous generator/condenser and transformer volts per hertz capability;
- Time vs. field current or time vs. stator current; and
- Distributed control system (DCS) voltage/VAR limit settings.

B. IBR generating Facility equipment capabilities, control functions, and protective functions, which shall be coordinated if enabled, include but are not limited to:

- Transformer overvoltage protective function;
- Transformer undervoltage protective function;
- Transformer volts per hertz capability and protective function;
- Collector bus overvoltage protective function;
- Collector bus undervoltage protective function;
- Reactive compensating devices voltage control functions;
- Reactive compensating devices voltage protective function;
- Collector feeder phase overvoltage protective function;
- Collector feeder phase undervoltage protective function;
- Collector feeder overcurrent limiter;
- IBR unit phase lock loop protective function;
- IBR unit overcurrent limiter;
- IBR unit momentary cessation (cease current injection) protective function;

- IBR unit phase overvoltage protective function;
- IBR unit phase undervoltage protective function; and
- IBR unit phase overcurrent protective function.

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

(DELETE GREEN TEXT PRIOR TO PUBLISHING) Describe the type of action associated with this posting, such as 30-day informal comment period, 45-day formal comment period with ballot, 45-day formal comment period with additional ballot, final ballot. Note that "Anticipated Actions" once finished should move up to "Completed Actions" section for each new draft.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	March 4 – April 2, 2021

Anticipated Actions	Date
45-day formal or informal comment period with ballot	September – November 2022
45-day formal or informal comment period with additional ballot	February – April 2023
10-day final ballot	May 2023
Board adoption	August 2023

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:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

2. **Number:** ~~PRC-019-2~~PRC-019-3

3. **Purpose:** To verify coordination of generating unit or Facility ~~or synchronous condenser~~ voltage regulating controls, limit functions, equipment capabilities ~~and Protection System settings~~, and protective functions.

4. **Applicability:**

   4.1. Functional Entities

   4.1.1 Generator Owner

   4.1.2 Transmission Owner ~~that owns synchronous condenser(s)~~

   4.2. Facilities

   For the purpose of this standard, the term, "applicable Facility" or "Facility" shall mean any one of the following:

   4.2.1 Individual generating ~~unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.~~resource identified through Inclusion I2 of the BES definition.

   4.2.2 Generating plant/Facility identified through Inclusion I2 of the BES definition.

   ~~**4.2.2** Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.~~

   ~~**4.2.3** Generating plant/ Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).~~

   4.2.3 ~~**4.2.3.1**This includes individual generating units of the dispersed power producing~~ Dynamic reactive resources identified through Inclusion ~~I4 of the Bulk Electric System definition where voltage regulating control for the facility is performed solely at the individual generating unit of the dispersed power producing resources.~~ I5 of the BES definition with a gross (individual or aggregate) nameplate rating greater than 20 MVA including:

   4.2.3.1 Synchronous condenser.

   4.2.4 Inverter-based resource (IBR) generating plant/Facility identified through Inclusion I4 of the BES definition, including:

   4.2.4.1 Individual IBR units;

4.2.4.2 Collector bus(es) and collector feeder(s);

4.2.4.3 Static or dynamic reactive compensating devices;

4.2.4.4 Main power transformer (MPT);[1]

4.2.4.5 Generator step-up (GSU) transformer(s);[2]

4.2.5 Any Blackstart Resource.

~~**4.2.4** Any generator, regardless of size, that is a blackstart unit material to and designated as part of a Transmission Operator's restoration plan.~~

5. Effective Date:

See the Implementation Plan for ~~PRC-019-2~~PRC-019-3.

B. Requirements and Measures

R1. At a maximum of every ~~five~~ six calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate[3] the voltage regulating system controls, ~~(including in-service [1]limiters and protection functions)~~ with the applicable equipment capabilities and settings of the applicable ~~Protection System devices and functions~~protective functions.[4] Equipment capabilities, control functions, and protective functions for the applicable Facilities include, but are not limited to those listed in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. ~~Assuming~~ For synchronous generators or synchronous condensers, assuming the normal automatic voltage regulator control loop and steady-state system operating conditions, verify the following coordination items ~~for each applicable Facility~~:

[1] 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.

[2] For the purpose of this standard, the GSU is the power transformer that steps up voltage from the individual IBR unit to the nominal collection system voltage for dispersed power producing resources.

[3] As-left settings shall be utilized in a protection and control coordination study.

~~[1] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.~~

[4] A protective function includes an action performed by a Protection System device or an action performed by a control system that replicates the behavior of a Protection System device in order to mitigate the consequences of an event that exceeds equipment design basis.

1.1.1. The in-service ~~limiters~~ limiter functions[5] are set to operate before the ~~Protection System~~ protective functions of the applicable Facility in order to avoid disconnecting the generator unnecessarily.

1.1.2. The applicable in-service ~~Protection System devices~~ protective functions are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities ~~or stability limits.~~.

1.2. For IBR generating Facilities, assuming the voltage control mode is enabled in the power plant controller and/or IBR unit(s)[6] and steady-state system operating conditions, verify the following coordination items:

1.2.1. The in-service control functions of the power plant controller are set to operate before the protective functions of the applicable Facilities in order to avoid disconnecting any of the Facilities listed under Section 4.2.4 unnecessarily.

1.2.2. The in-service control functions of IBR unit(s) are set to operate before protective functions of the applicable Facilities in order to avoid disconnecting any of Facilities listed under Section 4.2.4 unnecessarily.

1.2.3. The applicable in-service protective functions are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities.

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence such as a graphical representation(s) of coordination including a P-Q Diagram, R-X Diagram, Inverse Time Diagram, equivalent tables, steady-state calculations, dynamic simulation studies, or other evidence that it performed a coordination study as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

R2. ~~Within 90 calendar days following the identification or~~ Each Generator Owner and Transmission Owner shall perform the coordination described in Requirement R1 prior to implementation of systems, equipment ~~or setting~~ , or settings changes that will affect the coordination described in Requirement R1~~, each Generator Owner and Transmission Owner with applicable Facilities shall perform the coordination as described in Requirement R1~~; and update associated coordination documentation within 90 calendar days after the return to in-service date. These possible systems,

[5] Limiter functions that are installed and activated on the generator or synchronous condenser.

[6] IBR unit includes the inverter, converter, or wind turbine generator.

equipment or settings changes include, but are not limited to~~,~~ , the following~~–~~ : *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~:~~

- Voltage regulating settings or equipment changes;
- ~~Protection System~~ Protective function settings or component changes;
- ~~Generating~~ IBR unit, synchronous generator or synchronous condenser equipment capability changes; ~~or~~
- ~~Generator~~ IBR unit, synchronous generator or synchronous condenser step-up transformer changes~~.~~;
- IBR unit control system firmware or settings changes; or
- Power plant controller firmware or settings changes.

~~C. Measures~~

~~**M1.** Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the voltage regulating system controls, including in-service [2]limiters and protection functions, with the applicable equipment capabilities and settings of the applicable Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.~~

M2. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence of the coordination study required by the events listed in Requirement R2. This evidence should include dated documentation that demonstrates ~~the specified intervals in~~ Requirement R2 ~~have~~ has been met.

C. ~~D.~~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.

~~[2] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.~~

~~The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.~~

~~**1.2. Evidence Retention**~~

1.2. **Evidence Retention:** The following evidence retention ~~periods~~ period(s) identify ~~a~~ 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 ~~compliance~~ 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 Requirement R1 of the most recent coordination study.
- The Generator Owner and Transmission Owner shall ~~retain evidence of compliance with Requirements R1 and R2, Measures M1 and M2 for six years.~~ keep data or evidence of Requirement R2 of the most recent coordination study.

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.

~~If a Generator Owner or Transmission Owner is found non-compliant, the entity shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.~~

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

~~1.3. Compliance Monitoring and Assessment Processes~~

~~Compliance Audit~~

~~Self-Certification~~

~~Spot Checking~~

~~Compliance Investigation~~

~~Self-Reporting~~

~~Complaint~~

~~1.4. Additional Compliance Information~~

~~None~~

~~2.~~Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Generator Owner or Transmission Owner coordinated equipment capabilities, ~~limiters~~control functions, and protection specified in Requirement R1 ~~more than 5 calendar years but less than or equal to 5~~	The Generator Owner or Transmission Owner coordinated equipment capabilities, ~~limiters~~control functions, and protection specified in Requirement R1 ~~more than 5 calendar years plus 4 months but less than or~~	The Generator Owner or Transmission Owner coordinated equipment capabilities, ~~limiters~~control functions, and protection specified in Requirement R1 ~~more than 5 calendar years plus 8 months but less than or~~	The Generator Owner or Transmission Owner ~~failed to coordinate~~ coordinated equipment capabilities, ~~limiters~~control functions, and protection specified in Requirement R1 ~~within 5 calendar years plus 12~~

	~~calendar years plus 4~~ between 6 years (72 months) and 76 months after the previous coordination.	~~equal to 5 calendar years plus 8~~ between 77 and 81 months after the previous coordination.	~~equal to 5 calendar years plus 12~~ between 82 and 86 months after the previous coordination.	more than 86 months after the previous coordination. OR The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection as specified in Requirement R1.
~~R2~~R2.	The Generator Owner or Transmission Owner ~~coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.~~ updated associated coordination documentation as specified in Requirement R2 between 91 and 120 calendar days after return to in-service date.	The Generator Owner or Transmission Owner ~~coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.~~ updated associated coordination documentation as specified in Requirement R2 between 121 and 150 calendar days after return to in-service date.	The Generator Owner or Transmission Owner ~~coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.~~ updated associated coordination documentation as specified in Requirement R2 between 151 and 180 calendar days after return to in-service date.	The Generator Owner or Transmission Owner failed to update associated coordination documentation as specified in Requirement R2 within 151 calendar days after return to in-service date. OR The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 ~~within 120 calendar days following the identification or implementation of~~ prior to the implementing a change in equipment or settings that affected the coordination.

D. ~~E.~~ Regional Variances

None.

E. ~~F.~~Associated Documents

"Underexcited Operation of Turbo Generators", AIEE Proceedings T Section 881, Volume 67, 1948, Appendix 1, C. G. Adams and J. B. McClure.

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

"Coordination of Generator Protection with Generator Excitation Control and Generator Capability", a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee

"IEEE C37.102-2006 IEEE Guide for AC Generator Protection"

"IEEE C50.13-2005 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above"

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

Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New
1	March 20, 2014	FERC Order issued approving PRC-019-1. (Order becomes effective on 7/1/16.)	
2	February 12, 2015	Adopted by 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-019-2	Modifications to adjust the applicability to owners of dispersed generation resources.
3	*Date*	Adopted by NERC Board of Trustees	Standard revised in Project 2021-01

~~G. Reference~~

~~Examples of Coordination~~

~~The evidence of coordination associated with Requirement R1 may be in the form of:~~

- ~~P-Q Diagram (Example in Attachment 1), or~~

~~•R-X Diagram (Example in~~ **Attachment** ~~2), or~~**1: Equipment Capabilities, Types of Limiters, and Protective Functions**

NOTE: This standard does not require the installation or activation of any of the limiter or protection functions for synchronous generation or IBR.

- ~~Inverse Time Diagram (Example in Attachment 3) or,~~
- ~~Equivalent tables or other evidence~~

A. ~~This evidence should include the~~ Synchronous generation equipment capabilities ~~and the operating region for the limiters and protection functions~~, control functions, and protective functions, which shall be coordinated if enabled, include but are not limited to:

- Synchronous generator/condenser reactive capabilities;

~~Equipment limits, types of limiters and protection functions which could be coordinated include (but are not limited to):~~

- Field over-excitation limiter and associated ~~protection functions.~~protective function;
- ~~Inverter over current limit and associated protection functions.~~
- Field under-excitation limiter and associated ~~protection functions.~~protective function;
- ~~Generator or synchronous condenser reactive capabilities.~~
- Volts per hertz limiter and associated ~~protection functions.~~protective function;
- Stator over-voltage protection system settings~~.~~;
- ~~Generator~~ Synchronous generator/condenser and transformer volts per hertz capability~~.~~;
- Time vs. field current or time vs. stator current; and
- Distributed control system (DCS) voltage/VAR limit settings.

~~**NOTE:** This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions.~~

~~For this example, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current.~~

~~On a P-Q diagram using X_d as the direct axis saturated synchronous reactance of the generator, X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer and V_g as the generator terminal voltage (all values in per-unit), the SSSL can be calculated as an arc with the center on the Q axis with the magnitude of the center and radius described by the following equations~~

$$\cancel{C = V^2_g/2*(1/X_s-1/X_d)}$$

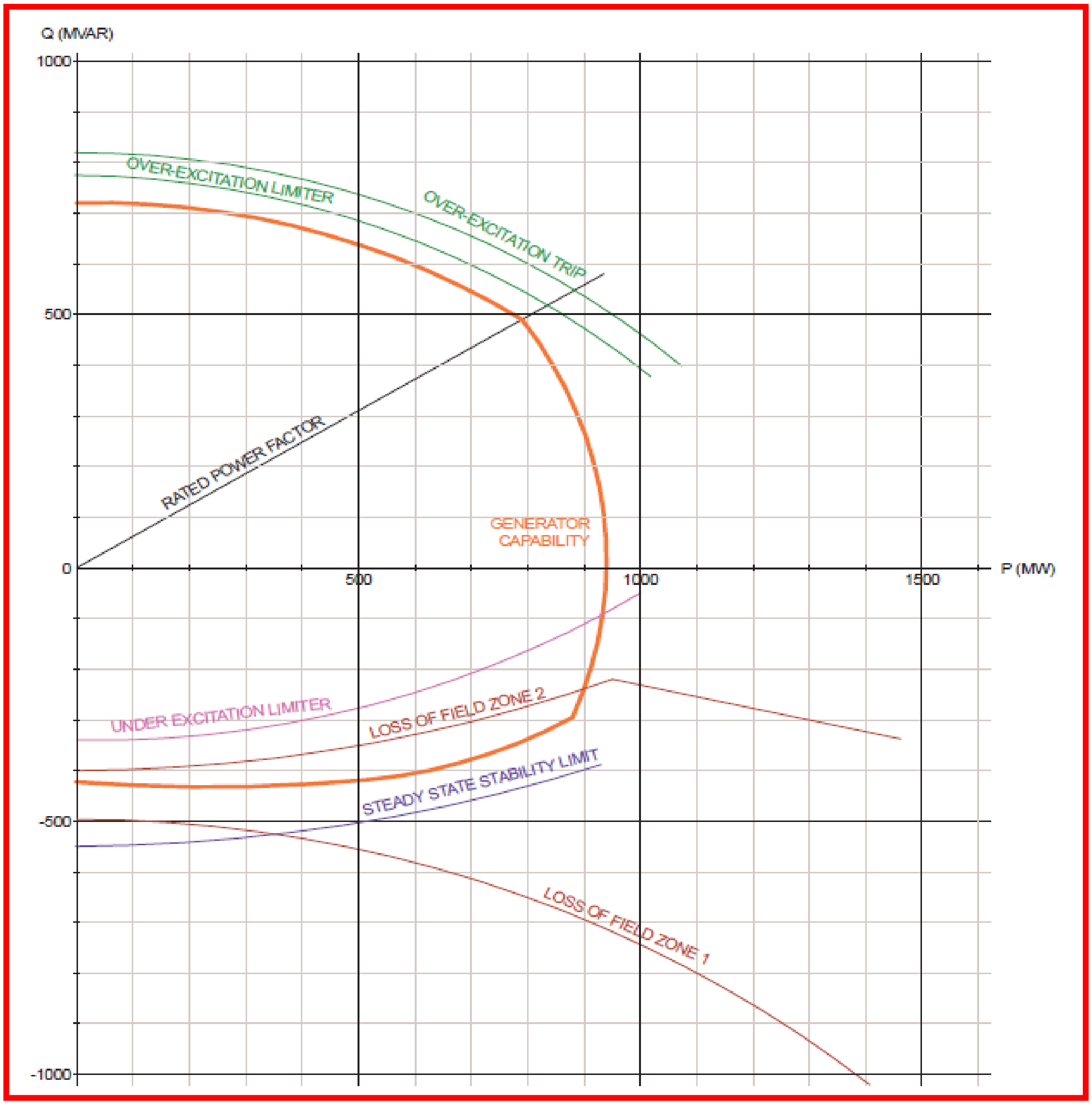
$$\cancel{R = V^2_g/2*(1/X_s+1/X_d)}$$

~~On an R-X diagram using X_d as the direct axis saturated synchronous reactance of the generator, and X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer the SSSL is an arc with the center on the X axis with the center and radius described by the following equations:~~

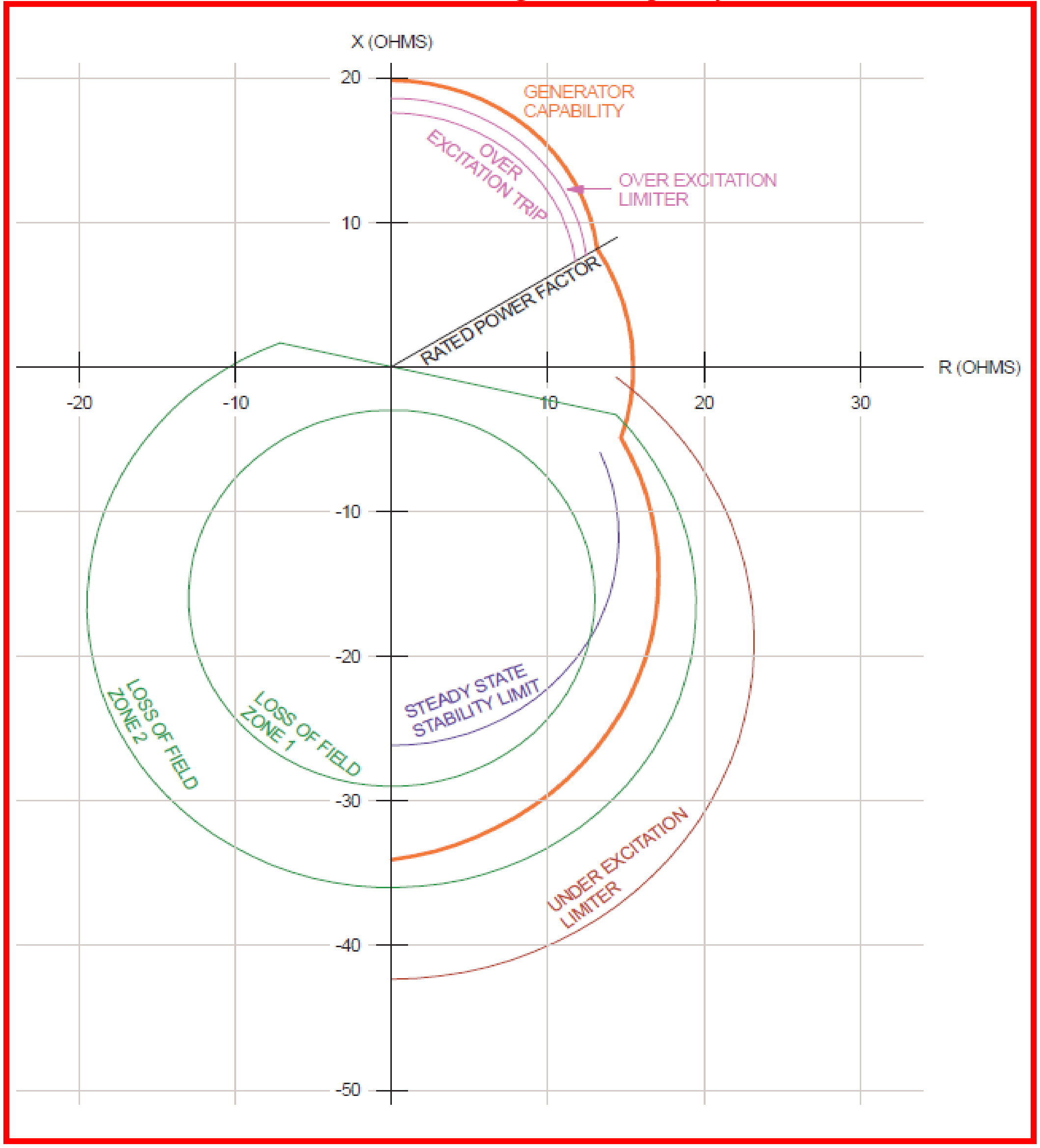
$$\cancel{C = (X_d-X_s)/2}$$

$$\cancel{R = (X_d+X_s)/2}$$

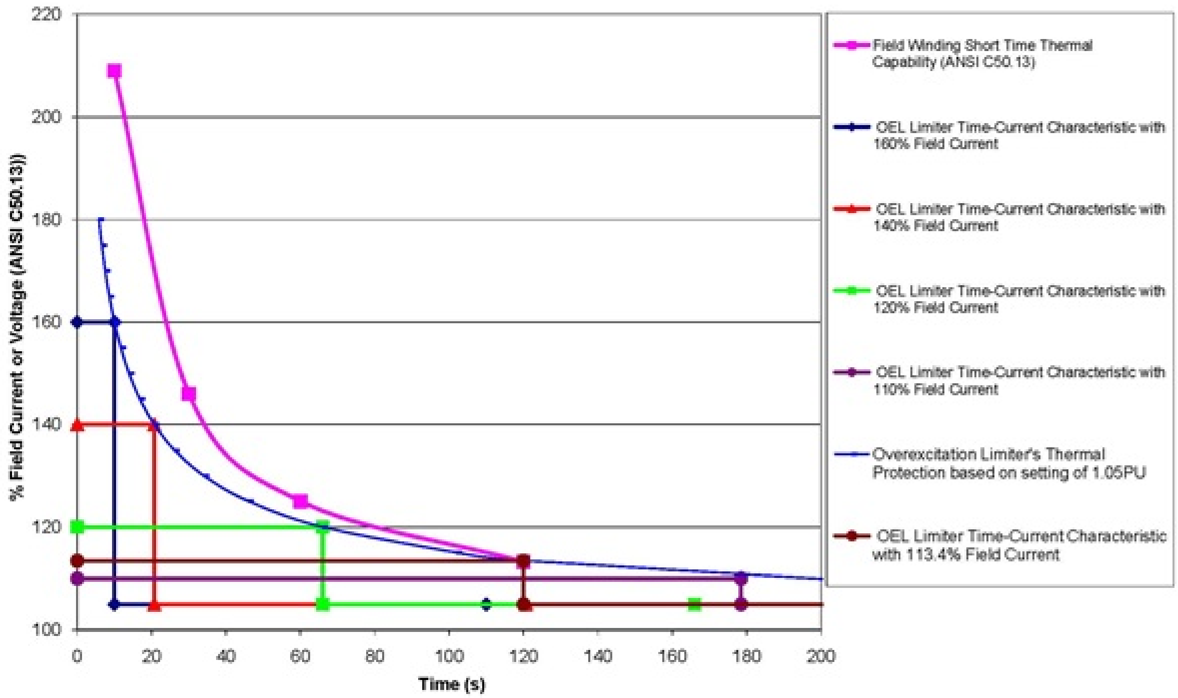
~~Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency~~


Q (MVAR)
1000
500
0
-500
-1000
500
1000
1500
P (MW)
OVER-EXCITATION LIMITER
OVER-EXCITATION TRIP
RATED POWER FACTOR
GENERATOR
CAPABILITY
UNDER EXCITATION LIMITER
LOSS OF FIELD ZONE 2
STEADY STATE STABILITY LIMIT
LOSS OF FIELD ZONE 1

~~Section G Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal voltage and frequency~~



~~Section G Attachment 3 - Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot~~


220
200
180
160
140
120
100
% Field Current or Voltage (ANSI C50.13))
0
20
40
60
80
100
120
140
160
180
200
Time (s)
Field Winding Short Time Thermal Capability (ANSI C50.13)
OEL Limiter Time-Current Characteristic with 160% Field Current
OEL Limiter Time-Current Characteristic with 140% Field Current
OEL Limiter Time-Current Characteristic with 120% Field Current
OEL Limiter Time-Current Characteristic with 110% Field Current
Overexcitation Limiter's Thermal Protection based on setting of 1.05PU
OEL Limiter Time-Current Characteristic with 113.4% Field Current

~~**Rationale:**~~

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

~~**Rationale for Facilities section 4.2.3.1**~~

~~For those dispersed power producing facilities that only perform voltage regulating control at the individual generating unit level, the SDT believes that coordination should take place at the individual generating unit level of the dispersed power producing resource. These facilities need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. Where voltage regulating control is done at an aggregate level, applicability is already included under Facilities section 4.2.3.~~

B. IBR generating Facility equipment capabilities, control functions, and protective functions, which shall be coordinated if enabled, include but are not limited to:

- Transformer overvoltage protective function;
- Transformer undervoltage protective function;
- Transformer volts per hertz capability and protective function;
- Collector bus overvoltage protective function;
- Collector bus undervoltage protective function;
- Reactive compensating devices voltage control functions;
- Reactive compensating devices voltage protective function;
- Collector feeder phase overvoltage protective function;
- Collector feeder phase undervoltage protective function;
- Collector feeder overcurrent limiter;
- IBR unit phase lock loop protective function;
- IBR unit overcurrent limiter;
- IBR unit momentary cessation (cease current injection) protective function;
- IBR unit phase overvoltage protective function;
- IBR unit phase undervoltage protective function; and
- IBR unit phase overcurrent protective function.

Implementation Plan

Project 2021-01 Modifications to MOD-025 and PRC-019 | Reliability Standard MOD-025-3

Applicable Standard(s)

- MOD-025-3 Verification of Real and Reactive Power Capability for BES Facilities

Requested Retirement(s)

- MOD-025-2 Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Prerequisite Standard(s)

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

- None

Applicable Entities

- Generator Owner
- Transmission Owner
- Transmission Planner

New/Modified/Retired Terms in the NERC Glossary of Terms

None

General Considerations

The standard drafting team chose to use a phased-in implementation period for some Requirements considering the revisions made within the standard. Requirement R3 and R4 will have the effective date of MOD-025-3, whereas Requirement R1 and R2 will have a later compliance date as described below.

This implementation plan reflects the consideration of the following factors:

- MOD-025-2 utilized a 5 year implementation period
- New Applicable Entities (Transmission Planner)
- New Applicable Facilities (FACTS devices, and HVDC equipment)

- Limited amount of subject matter experts in industry and vendors that are able to implement the requirements in this standard

Effective Date and Phased-In Compliance Dates

The effective date(s) for the proposed Reliability Standard 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 date for those particular sections represents the date that entities must begin to comply with that particular section of the Reliability Standard, even when the Reliability Standard goes into effect at an earlier date.

Reliability Standard MOD-025-3

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 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.

Compliance Date for MOD-025-3 – Requirements R1 and R2

Applicable Entities shall not be required to comply with Requirement R1 and R2 until twenty-four (24) months after the effective date of Reliability Standard MOD-025-3.

Retirement Date

MOD-025-2

Reliability Standard MOD-025-2 shall be retired immediately prior to the effective date of MOD-025-3 in the particular jurisdiction in which the revised standard is becoming effective.

Initial Performance of Periodic Requirements

For Applicable Facilities commissioned after the Effective Date of MOD-025-3, Applicable Entities shall comply with Requirements R1 and R2 of MOD-025-3 by 180 calendar days after the commissioning date in accordance with MOD-025-3 Attachment 1.

Implementation Plan

Project 2021-01 Modifications to MOD-025 and PRC-019 | Reliability Standard PRC-019-3

Applicable Standard(s)

- PRC-019-3 Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Requested Retirement(s)

- PRC-019-2 Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Prerequisite Standard(s)

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

- None

Applicable Entities

- Generator Owner
- Transmission Owner

New/Modified/Retired Terms in the NERC Glossary of Terms

None

General Considerations

The standard drafting team chose to apply a six (6) year periodicity for Requirement R1 from the last date a protection coordination study was performed. See *Initial Performance of Periodic Requirements* section for more detail. Requirement R2 would have the same effective date as the standard, PRC-019-3.

This implementation plan reflects the consideration of the following factors:

- Maintain recurring periodicity were appropriate
- New language for Requirement R1, inverter based resources
- New language for Requirement R2

Effective Date and Phased-In Compliance Dates

The effective date(s) for the proposed Reliability Standard 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 date for those particular sections represents the date that entities must begin to comply with that particular section of the Reliability Standard, even when the Reliability Standard goes into effect at an earlier date.

Reliability Standard PRC-019-3

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 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.

Retirement Date

PRC-019-2

Reliability Standard PRC-019-2 shall be retired immediately prior to the effective date of PRC-019-3 in the particular jurisdiction in which the revised standard is becoming effective.

Initial Performance of Periodic Requirements

Applicable Entities shall initially comply with the periodic requirements of PRC-019-3 (Requirement R1) within six (6) years of their last performance under the respective requirement in the Requested Retired Standards (PRC-019-2 Requirement R1).

For an applicable Facility commissioned after the Effective Date of PRC-019-3, which has not previously performed a coordination study under PRC-019-2 Requirement R1, the Applicable Entities shall comply with the requirements of PRC-019-3 prior to outputting Real or Reactive Power to the BES.

Project 2021-05 Modifications to PRC-023

Action

Authorize initial posting of proposed Reliability Standard PRC-023-6 and the associated Implementation Plan for a 45-day formal comment period, with ballot pool 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

The Project 2021-05 original Standard Authorization Request (SAR) was submitted by NERC System Protection and Control Subcommittee (also known as Protection and Control Working Group) to modify the PRC-023 standard to address potential reliability issues resulting from confusion regarding the applicability of Requirement R2 and Attachment A exclusion 2.3.

At the Standards Committee (SC) January 20, 2021 meeting, the SC accepted the SAR and authorized soliciting for members for the SAR Drafting Team (DT). From June 29 to July 28, 2021, NERC conducted an informal comment period for the NERC System Protection and Control Subcommittee SAR and solicited for the SAR DT members. The solicitation for the SAR Drafting Team member period was extended through August 10, 2021. At the SC September 23, 2021 meeting, the SC appointed chair, vice chair, and members to the Project 2021-05 Modifications to PRC-023 SAR DT. The SAR DT was appointed as the Standard Drafting Team (SDT) at the SC December 15, 2021 meeting.

From January 31, 2022 to August 4, 2022, the SDT conducted 16 conference calls to make revisions to the standard language, associated Implementation Plan, and VRFs and VSLs.

The Quality Review (QR) for this posting was performed from August 17, 2022 through August 25, 2022. The QR team members from NERC are Lauren Perotti, Jon Hoffman, Scott Barfield, Ryan Mauldin, Teri Stasko, Latrice Harkness, and Alison Oswald. The SDT also reached out to the industry for additional QR. The QR members from the industry include, but were not limited to, Jeff Brogdon (Georgia Transmission Corporation), Chris Culpepper (Siemens Industry Inc.), and Kevin Jones (Xcel Energy).

The SDT reviewed all comments and revised the proposed Standard and Implementation Plan where appropriate.

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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/29/2021 – 07/28/2021

Anticipated Actions	Date
45-day formal or informal comment period with ballot	10/03/2022 – 11/17/2022
~~XX~~45-day formal or informal comment period with additional ballot	12/05/2022 – 01/18/2023
~~XX~~10-day final ballot	02/13/2023 – 02/22/2023
Board adoption	03/22/2023

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):

N/A.

A. Introduction

1. **Title:** **Transmission Relay Loadability**
2. **Number:** PRC-023-~~5~~6
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**

4.1. Functional Entity:

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-~~5~~6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-~~5~~6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-~~5~~6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits:

4.2.1 Circuits Subject to Requirements R1 – R5:

4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. **Effective Dates:** See Implementation Plan. See Implementation Plan. As provided therein, each Generator Owner, Transmission Owner, and Distribution Provider that owns circuits that become applicable to this standard pursuant to Requirement R6 shall become compliant with R1 through R5 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*.

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
   - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
   - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
   - 115% of the highest emergency rating of the series capacitor.
   - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.

5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

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[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

6. ~~Not used.~~Reserved
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.
8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
    - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
    - 115% of the highest operator established emergency transformer rating.

    10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
    - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
    - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
    a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.
    b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration,* Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot

temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

~~**criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)**~~

R2. **Reserved.** ~~Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.~~ ~~*[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*~~

M2. Reserved.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-~~5~~6, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-~~5~~6 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-~~5~~6, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-6, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

~~**6.2**~~

~~by: (i),; (ii)the ,~~

~~C. Measures~~

~~**M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays setper~~

~~criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)~~

~~M2.~~ Reserved. ~~Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)~~

~~**M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)~~

~~**M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)~~

~~**M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)~~

~~**M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-56, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)~~

~~D.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator 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 Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

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

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

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	**Reserved.**~~The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.~~
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met

Requirement	Lower	Moderate	High	Severe
		the list was established or updated. (part 6.2)		6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

~~E.~~D. Regional ~~Differences~~Variances

None.

~~F.~~E. ~~Supplemental Technical Reference Document~~Associated Documents

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

   "Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

   NERC Reliability Standard PRC-023-6 Implementation Plan.

   NERC Reliability Standard PRC-023-6 Technical Rationale.

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.

Version	Date	Action	Change Tracking
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	
5	May 13, 2021	Adopted by the NERC Board of Trustees	
5	DATE	Add FERC approval history	
6		Revised by Project….	Retired Requirement R2, remove Attachment A, Section/Part 2.3

PRC-023-~~5~~6 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

   1.1. Phase distance.

   1.2. Out-of-step tripping.

   1.3. Switch-on-to-fault.

   1.4. Overcurrent relays.

   1.5. Communications aided protection schemes including but not limited to:

      1.5.1 Permissive overreach transfer trip (POTT).

      1.5.2 Permissive under-reach transfer trip (PUTT).

      1.5.3 Directional comparison blocking (DCB).

      1.5.4 Directional comparison unblocking (DCUB).

   1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

   2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:

   - Overcurrent elements that are only enabled during loss of potential conditions.
   - Elements that are only enabled during a loss of communications except as noted in section 1.6.

   2.2. Protection systems intended for the detection of ground fault conditions.

   2.3. Reserved.~~Protection systems intended for protection during stable power swings.~~

   2.4. ~~Not used.~~Reserved

   2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

   2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

   2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

   2.8. Relay elements associated with dc lines.

   2.9. Relay elements associated with dc converter transformers.

PRC-023-~~5~~6 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator or Transmission Planner based on Planning Assessments of the Near-Term Transmission Planning Horizon that identify instances of instability, Cascading, or uncontrolled separation, that adversely impact the reliability of the Bulk Electric System for planning events.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/29/2021 – 07/28/2021

Anticipated Actions	Date
45-day formal or informal comment period with ballot	10/03/2022 – 11/17/2022
XX-day formal or informal comment period with additional ballot	12/05/2022 – 01/18/2023
XX-day final ballot	02/13/2023 – 02/22/2023
Board adoption	03/22/2023

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):

N/A.

A. Introduction

1. **Title:** **Transmission Relay Loadability**

2. **Number:** PRC-023-6

3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

4. **Applicability:**

4.1. Functional Entity:

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits:

4.2.1 Circuits Subject to Requirements R1 – R5:

4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. **Effective Dates:** See Implementation Plan. See Implementation Plan. As provided therein, each Generator Owner, Transmission Owner, and Distribution Provider that owns circuits that become applicable to this standard pursuant to Requirement R6 shall become compliant with R1 through R5 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning].*

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
   - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
   - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
   - 115% of the highest emergency rating of the series capacitor.
   - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.

5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

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[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

6. Reserved
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.
8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
    - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
    - 115% of the highest operator established emergency transformer rating.

    10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
    - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
    - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
    a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.
    b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration,* Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot

temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

R2. Reserved.

M2. Reserved.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-6, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-6 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-6, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-6, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator 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 Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

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

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

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	**Reserved.**
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met

Requirement	Lower	Moderate	High	Severe
		the list was established or updated. (part 6.2)		6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

D. Regional Variances

None.

E. Associated Documents

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

   "Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

   NERC Reliability Standard PRC-023-6 Implementation Plan.

   NERC Reliability Standard PRC-023-6 Technical Rationale.

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.

Version	Date	Action	Change Tracking
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	
5	May 13, 2021	Adopted by the NERC Board of Trustees	
5	DATE	Add FERC approval history	
6		Revised by Project….	Retired Requirement R2, remove Attachment A, Section/Part 2.3

PRC-023-6 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

   1.1. Phase distance.

   1.2. Out-of-step tripping.

   1.3. Switch-on-to-fault.

   1.4. Overcurrent relays.

   1.5. Communications aided protection schemes including but not limited to:

   1.5.1 Permissive overreach transfer trip (POTT).

   1.5.2 Permissive under-reach transfer trip (PUTT).

   1.5.3 Directional comparison blocking (DCB).

   1.5.4 Directional comparison unblocking (DCUB).

   1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

   2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:

   - Overcurrent elements that are only enabled during loss of potential conditions.
   - Elements that are only enabled during a loss of communications except as noted in section 1.6.

   2.2. Protection systems intended for the detection of ground fault conditions.

   2.3. Reserved.

   2.4. Reserved

   2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

   2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

   2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

   2.8. Relay elements associated with dc lines.

   2.9. Relay elements associated with dc converter transformers.

PRC-023-6— Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator or Transmission Planner based on Planning Assessments of the Near-Term Transmission Planning Horizon that identify instances of instability, Cascading, or uncontrolled separation, that adversely impact the reliability of the Bulk Electric System for planning events.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

   i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

   ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

   iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

Implementation Plan (Draft)

Project 2021-05 Modifications to PRC-023
Reliability Standard PRC-023-6

Applicable Standard(s)

- PRC-023-6 –Transmission Relay Loadability

Requested Retirement(s)

- PRC-023-5 – Transmission Relay Loadability

Applicable Entities

- Transmission Owner
- Generator Owner
- Distribution Provider

General Considerations

None.

Effective Date

Where approval by an applicable governmental authority is required, Reliability Standard PRC-023-6 shall become effective on the later of: (i) the first day of the first calendar after the effective date of the applicable governmental authority's order approving the standard or as otherwise provided for by the applicable governmental authority; or (ii) the effective date of Reliability Standard PRC-023-5.

Where approval by an applicable governmental authority is not required, Reliability Standard PRC-023-6 shall become effective on the later of: (i) the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction; or (ii) the effective date of Reliability Standard PRC-023-5.

Retirement Date

The version of Reliability Standard PRC-023 then in effect shall be retired immediately prior to the effective date of the proposed Reliability Standard PRC-023-6.

Initial Performance Date

Each Planning Coordinator shall conduct its first assessment under Reliability Standard PRC-023-6 within the next calendar year after the effective date or within 15 months of their last assessment under PRC-023-4 or PRC-023-5, whichever occurs first.

Time Period to Address New Designations

Each Transmission Owner, Generator Owner, and Distribution Provider that owns circuits that become applicable to this standard pursyant to Requirement R6 shall become compliant with R1 through R5 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

2023-2025 Reliability Standards Development Plan

Action
Endorse the 2023-2025 Reliability Standards Development Plan (RSDP).

Background
Section 310 of the NERC Rules of Procedure requires NERC to develop and provide an annual RSDP to the applicable governmental authorities. The draft 2023-2025 RSDP includes time frames and anticipated resources for each project under development or anticipated to begin by the end of the year. NERC and the Standards Committee will continue to work with NERC committees and task forces to bridge any potential reliability gaps and risks.

A draft RSDP was circulated and then posted for informal industry comment from July 26 to August 24, 2022. The RSDP will be presented to the NERC Board of Trustees in November 2022 and subsequently submitted to the applicable governmental authorities for information. In the event a Standard Authorization Request or FERC directive is received prior to submitting the RSDP, the document will be updated appropriately.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Agenda Item 13a
Standards Committee
September 21, 2022

Reliability Standards Development Plan

2023-2025

September 21, 2022

RELIABILITY | RESILIENCE | SECURITY




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Table of Contents

Background

Pursuant to Section 310 of the NERC Rules of Procedure, NERC is required to develop and provide to applicable governmental authorities an annual Reliability Standards Development Plan (RSDP) for Reliability Standards development. Each annual RSDP must include a progress report comparing results achieved to the prior year's RSDP. NERC is required to consider the comments and priorities of the applicable governmental authorities in developing and updating the annual RSDP. NERC also provides the RSDP to the NERC Standards Committee (SC) for review and posts the RSDP for industry comment.

As described herein, this RSDP for 2023-2025 builds upon the goals of the previous RSDPs.

Executive Summary

The 2023-2025 RSDP provides insight into standards development activities anticipated at the time of publication so that stakeholders may make available resources needed to accomplish the standards development objectives. Additional activities such as Requests for Interpretation and Regional Variance development may impact the plan and are included at this time. In order to help the industry understand resource requirements for each project, the RSDP now shows time frames and anticipated resources for each project under development.

This RSDP contemplates that the work of the Reliability and Security Technical Committee (RSTC) and working groups thereunder may result in more Standard Authorization Requests (SARs) and subsequent standards projects. It is also important to note that projects may be generated through the use of the Electric Reliability Organization risk framework.

Periodic Reviews and initiatives, such as the final recommendations of the Standards Efficiency Review (SER) project, also enable NERC to identify requirements that do little to promote reliability and should therefore be retired. Periodic Reviews will occur at a measured pace compared to the level of activity and pace of standards development during recent years. Additionally, Periodic Reviews will be aligned with the strategic consideration of reviewing standard families that are interrelated.[1] The Standards Grading effort for 2022 has been completed and results are included.

While most of the work in the next three years will focus on new SARs, Periodic Reviews, SER implementation, and Standards Grading, there may be new or emerging risks identified that could generate new standards development projects. NERC will continue to seek input and recommendations from the Reliability Issues Steering Committee (RISC) with regard to emerging or potential risks to Bulk Electric System (BES) reliability that may require revisions to existing standards or new standards development.

To help determine the impact of potential risk to BES reliability, NERC will use a variety of feedback mechanisms, including but not limited to, the Compliance Monitoring and Enforcement Program, RISC profiles, Events Analysis, and Compliance violation statistics, as well as any published "Lessons Learned." The Regional Entities also have feedback mechanisms in place to solicit comments from industry and to help identify approaches to meet concerns and provide input to the standards. Input into standards will also continue to be coordinated with the North American Energy Standards Board as appropriate. In assessing feedback to create new or revised standards, NERC will focus on risk, reliability or security data, and enforcement information to determine whether a standard revision is the best tool to initially address the reliability risk.

[1] The Periodic Review Standing Review Team grades the standards prior to conducting Periodic Reviews. The team includes representatives from NERC, the Regional Entities, and RSTC. If the standard is revised through the standard development process in response to a Periodic Review recommendation(s), the Periodic Review Standing Review Team will re-grade the standard with the revised language.

Progress Report

Pursuant to Section 310 of the NERC Rules of Procedure, NERC offers the following progress report on Reliability Standards development.

FERC Directives

As of June 30, 2022, there are two[2] outstanding directives being resolved through the standards development process. The status of the Standards directives are reported quarterly to the NERC Board of Trustees (Board).

Continuing Projects

All of the other projects from the previous RSDP are complete, or are expected to be complete this year, except the following, which will continue into 2023:

1. Project 2017-01 Modifications to BAL-003-1.1 (phase 2)
2. Project 2019-04 Modifications to PRC-005-6
3. Project 2020-02 Modifications to PRC-024 (Generator Ride-through)
4. Project 2020-04 Modifications to CIP-012
5. Project 2020-06 Verifications of Models and Data for Generators
6. Project 2021-01 Modifications to MOD-025 and PRC-019
7. Project 2021-02 Modifications to VAR-002
8. Project 2021-03 CIP-002 Transmission Owner Control Centers
9. Project 2021-04 Modifications to PRC-002-2
10. Project 2021-05 Modifications to PRC-023
11. Project 2021-06 Modifications to IRO-010 and TOP-003
12. Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination (Phase 2)
13. Project 2021-08 Modifications to FAC-008
14. Project 2022-01 Reporting ACE Definition and Associated Terms
15. Project 2022-02 Modifications to TPL-001-5.1 and MOD-032-1
16. Project 2022-03 Energy Assurance with Energy–Constrained Resources
17. Project 2022-04 EMT Modeling

Additional project information is available on the NERC website on the Standards web page.[3]

[2] The following projects are currently modifying standards to address directives: 2020-04 Modifications to CIP-012 (requirement for protections regarding the availability of communication links and data communicated between bulk electric system Control Centers). The second directive is a requirement to submit project schedules for one ongoing CIP project.

[3] As of the date of publication, the subject web page resides at http://www.nerc.com/pa/Stand/Pages/default.aspx.

The following projects have been, or are planned to be, completed in 2022 (actual and anticipated Board adoption dates are noted):

1. Project 2016-02 Modifications to CIP Standards (anticipated Board adoption December 2022)
2. Project 2020-03 Supply Chain Low Impact Revisions (anticipated Board adoption November 2022)
3. Project 2020-05 Modifications to FAC-001-3 and FAC-002-2 (adopted by the Board May 2022)
4. Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination (Phase 1) (anticipated Board adoption October 2022)

2023 Projects

Projects Continuing into 2023

In determining high, medium, or low priority designations for projects as listed in this RSDP, the following factors were taken into consideration:

- Outstanding regulatory directives with filing deadlines (High Priority)
- RISC category rankings of high impact with consideration of probability of occurrence (High or Medium Priority)
- Potential reliability risks from stakeholders provided through feedback mechanisms (High, Medium, or Low Priority, based on the risk)
- Outstanding regulatory directives without regulatory deadlines or "soft directives" such as considerations (High or Medium Priority)
- Outstanding requirements that are known candidates for retirement (Medium or Low Priority)
- Any known adverse content and quality assessments (likely Low Priority, as any reliability gaps identified have already been addressed)

High Priority

- Project 2020-04 Modifications to CIP-012 (drafting estimated to be completed by November 2021 requiring approximately 8 industry subject matter experts for approximately 100 work hours each for the remaining part of this project)
- Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination (drafting estimated to be completed in two phases over 2022-2023; first phase expected to be completed by September 2022 requiring 15 subject matter experts for approximately 175 work hours each for Phase 1 and Phase 2 of this project)
- Project 2021-03 CIP-002 Transmission Owner Control Centers (drafting estimated to be completed by August 2023 requiring approximately 10 subject matter experts for approximately 40 work hours each for this project). Three additional SARs pertaining to CIP-002 are assigned to this project. Additional subject matter experts are being solicited to address these SARs (drafting estimated to be completed by November 2023 requiring approximately 10 subject matter experts for approximately 40 work hours each for this project)
- Project 2022-02 Modifications to TPL-001-5.1 and MOD-032-1 (drafting estimated to be completed by August 2023 requiring approximately 10 subject matter experts for approximately 40 work hours each for this project)
- Project 2022-03 Energy Assurance with Energy–Constrained Resources (drafting estimated to be completed by February 2023 requiring approximately 12-15 industry subject matter experts for approximately 120 work hours each for the remaining part of this project)

Medium Priority

- Project 2017-01 Modifications to BAL-003-1.1 (phase 2) (drafting estimated to be completed by February 2023 requiring approximately 10 subject matter experts for approximately 40 work hours each for this project)
- Project 2020-02 Modifications to PRC-024 (Generator Ride-through) (drafting estimated to be completed by November 2023 requiring approximately 9 industry subject matter experts for approximately 120 work hours each for the remaining part of this project)

- Project 2020-06 Verifications of Models and Data for Generators (drafting estimated to be completed by February 2023 requiring approximately 12 subject matter experts for approximately 40 work hours each for this project)
- Project 2022-04 EMT Modeling (drafting estimated to be completed by February 2024 requiring approximately 12 subject matter experts for approximately 40 work hours each for this project)

Low Priority

- Project 2019-04 Modifications to PRC-005-6 (drafting estimated to be completed by August 2023 requiring approximately 13 subject matter experts for approximately 40 work hours each for this project)
- Project 2021-01 Modifications to MOD-025 and PRC-019 (drafting estimated to be completed by May 2023 requiring approximately 12 subject matter experts for approximately 40 work hours each for this project)
- Project 2021-02 Modifications to VAR-002 (drafting estimated to be completed by May 2023 requiring approximately 13 subject matter experts for approximately 40 work hours each for this project)
- Project 2021-04 Modifications to PRC-002-2 (drafting estimated to be completed by May 2023 requiring approximately 10 subject matter experts for approximately 40 work hours each for this project)
- Project 2021-05 Modifications to PRC-023 (drafting estimated to be completed by May 2023 requiring approximately 10 subject matter experts for approximately 40 work hours each for this project)
- Project 2021-06 Modifications to IRO-010 and TOP-003 (drafting estimated to be completed by November 2023 requiring approximately 10 subject matter experts for approximately 40 work hours each for this project)
- Project 2021-08 Modifications to FAC-008 (drafting estimated to be completed by August 2023 requiring approximately 10 subject matter experts for approximately 40 work hours each for this project)
- Project 2022-01 Reporting ACE Definition and Associated Terms (drafting estimated to be completed by August 2023 requiring approximately 10 subject matter experts for approximately 40 work hours each for this project)

Other Projects Continuing into 2023

NERC Reliability Standards Efficiency Review Transition

In 2018, NERC began using both internal ERO Enterprise resources and industry resources to evaluate candidates for potential Reliability Standard retirements. NERC solicited industry participants to evaluate possible candidate requirements that may no longer be necessary to support reliability or address current risks to the Bulk Power System (BPS). Through open and transparent industry participation, the SER teams submitted a SAR to the SC in order to implement recommended changes to the body of Reliability Standards. The SAR was accepted at the August 2018 SC meeting, and the effort retired numerous standards and requirements in 2019.

The Standards Efficiency Review Report and Transition Plan outlines the Phase 1 and Phase 2 work, the additional recommendations, and closes out the SER. The SER recommendations are being implemented, which include Project 2021-06 Modifications to IRO-010 and TOP-003 regarding operational data exchange.

Standards Development Projects Overview

The NERC RSTC subcommittees, working groups, and task forces conduct work plan activities as assigned. Known and emerging risks are reviewed and assessed and may result in a SAR being submitted to initiate a standards development project. Also, as industry works to operate a reliable and secure grid, a SAR may be submitted to address risks.

As a result of the growth in use of inverters as part of the bulk power system, the NERC Inverter-based Resource (IBR) Performance Task Force (IRPTF) undertook an effort to perform a comprehensive review of all NERC Reliability Standards to determine if there were any potential gaps or improvements. The IRPTF identified several issues as part of this effort and documented its findings and recommendations in the "IRPTF Review of NERC Reliability Standards White Paper," which was approved in March 2020 by the Operating Committee and the Planning Committee (now part of the Reliability and Security Technical Committee (RSTC)). This assessment generated a number of projects listed in the RSDP.

The ERO's focus on cyber security is also at the forefront of addressing reliability risks. Standard development projects addressing virtualization and protecting cyber assets and communication links are a result of continued actions to keep the grid secure.

Other Projects Commencing

Currently, no Reliability Standards meet the criteria for periodic review in 2023. SARs, emerging risks to the BPS, and FERC regulatory directives that may occur subsequent to publishing this RSDP may prompt additional projects through 2023.

Standards Grading Metrics

The NERC SC endorsed the initial grading system for standards as a metric on March 9, 2016. The grading activity was directed by the NERC Board and was conducted by the Periodic Review Standing Review Team (PRSRT) as set forth in the Periodic Review process.[4] The PRSRT is comprised of the following:

- SRT Chair: SC Chair or (or SC Chair delegate)
- Representation from the Reliability and Security Technical Committee (RSTC)
- Representation from the Regional Entities
- NERC staff

The grading metrics include possible scores of 0-4 for content and 0-13 for quality. The set of standards chosen each year for grading, according to the criteria in the above section, will be graded to prioritize, and be a factor in determining the sequence they should enter into the Periodic Review process. At least one industry comment period will take place to allow industry to comment on the grading performed by the PRSRT. The grades, based on the PRSRT and any industry input, will be finalized, appended to the RSDP, and used to complete the prioritization each year. Additionally, input from other standards initiatives such as the Standards Efficiency Review (now completed), are being considered and coordinated with the Standards Grading activities.

[4] The process is detailed in the Periodic Review template, which is available at: https://www.nerc.com/pa/Stand/Resources/Documents/Periodic%20Review%20Template%20Feb%202016.pdf.

Attachment 1: Final Grades for Standards Considered in 2022

The PRSRT was tasked with using metrics from the 2013 Independent Experts Review Panel to assign numeric grades to instruct future Periodic Review teams.

While the PRSRT's final standards grades are important data points for the Periodic Reviews to consider, they are intended as one of many inputs to facilitate discussion during the reviews. Detailed analysis and background information on the Standards Grading process and PRSRT recommendations for periodic review project prioritization based on 2022 grades are posted on the project page.

2022 Standards Grades			
Standard	**Requirement**	**Content Average**	**Quality Average**
PER-003-2	R1.	4.00	12.67
PER-003-2	R2.	4.00	12.33
PER-003-2	R3.	4.00	12.67
PER-005-2	R1.	4.00	13.00
PER-005-2	R2.	4.00	13.00
PER-005-2	R3.	4.00	12.67
PER-005-2	R4.	4.00	13.00
PER-005-2	R5.	3.67	13.00
PER-005-2	R6.	3.67	13.00
PER-006-1	R1.	3.67	13.00
TPL-007-4	R1.	4.00	13.00
TPL-007-4	R2.	4.00	13.00
TPL-007-4	R3.	4.00	13.00
TPL-007-4	R4.	3.33	10.67
TPL-007-4	R5.	4.00	12.67
TPL-007-4	R6.	3.67	12.00
TPL-007-4	R7.	4.00	12.00
TPL-007-4	R8.	3.67	12.00
TPL-007-4	R9.	4.00	12.67
TPL-007-4	R10.	3.67	12.00
TPL-007-4	R11.	4.00	12.00
TPL-007-4	R12.	4.00	12.00
TPL-007-4	R13.	4.00	12.67

Revisions to the NERC Rules of Procedure Regarding Reliability Standards

Action
Information

Background
On Thursday, August 25, 2022, the Federal Energy Regulatory Commission (FERC) issued a notational order approving proposed changes to the NERC Rules of Procedure (ROP) regarding Reliability Standards. NERC originally submitted the changes to FERC for approval in August 2021. The specific sections and attachments revised include:

- Section 300, Reliability Standards Development
- Appendix 3B, Procedure for Election of Members of the Standards Committee
- Appendix 3D, Development of the Registered Ballot Body

The approved changes include language to clarify each entity's obligation as a member of the Registered Ballot Body (RBB) to deactivate duplicate RBB registrations following organizational changes such as mergers or acquisitions. The approved changes also include updated language and staff titles and revised reporting requirements that are intended to ensure that NERC's reporting to applicable governmental authorities is appropriate and provides the authorities with actionable information.

Redlines showing the changes and the supporting explanations are available in the August 12, 2021 Board of Trustees open meeting package (Agenda Item 5b) and NERC's March 18, 2022 amended petition to FERC.

Summary
Several of the approved changes affect member participation in the RBB. Legal staff will provide an overview of these changes, which are summarized as follows:

Section 300, Reliability Standards Development
Section 305: Clarified the obligation of entities to withdraw additional members of the RBB when a change in corporate structure (such as a merger or acquisition) results in the entity or affiliated entities having more than the one permitted representative in a particular Segment. Revised language regarding changing segments (Section 305.3.2) and review of Segment criteria (Section 305.3.3) for consistency with similar provisions in Appendix 3D.

Appendix 3D, Development of the RBB
Registration procedures: Clarified that the NERC General Counsel may delegate its responsibility to review applications to join the RBB to a member of the General Counsel's legal staff. This change is consistent with current practice.

Segment qualification guidelines: Clarified: (i) that NERC may remove individuals that have not completed the required annual self-selection process following written notice; and (ii) the obligation of entities to withdraw additional members of the RBB when a change in corporate structure (such as a merger or acquisition) results in the entity or affiliated entities having more than one representative in a particular Segment, consistent with changes to ROP Section 305.

NERC Legal and Regulatory Update
July 1, 2022 – September 1, 2022

NERC FILINGS TO FERC SUBMITTED SINCE LAST SC UPDATE

FERC Docket No.	Filing Description	FERC Submittal Date
RM21-10-001	Compliance Filing on CMEP ROP NERC submitted to FERC a compliance filing consisting of updates to the NERC Rules of Procedure (ROP) (Section 400 and Appendix 4C) in response to the May 19, 2022 Commission Order.	7/18/2022
RM21-17-000	Comments on Transmission Planning NOPR NERC and the Regional Entities submitted comments on the FERC Notice of Proposed Rulemaking (NOPR) regarding Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection.	8/17/2022
RM22-10-000	Comments on Transmission System Planning NERC and the Regional Entities submitted comments on the FERC Notice of Proposed Rulemaking (NOPR) regarding Transmission System Planning Performance Requirements for Extreme Weather.	8/26/2022
RM22-16-000; AD21-13-000	Comments on Extreme Weather Vulnerability Assessments NERC and the Regional Entities submit comments on the FERC Notice of Proposed Rulemaking (NOPR) regarding Extreme Weather Vulnerability Assessments.	8/30/2022

FERC ISSUANCES SINCE LAST SC UPDATE

FERC Docket No.	Order Description	FERC Issuance Date
RR21-8-000	Standards ROP Revisions Approved FERC issued an order approving revisions to Rules of Procedure regarding Reliability Standards.	8/25/2022

ANTICIPATED UPCOMING FILINGS

FERC Docket No.	Filing Description	Anticipated Filing Date
RM22-14-000	NOPR Comments: Improvements to Generator Interconnection Procedures and Agreements	10/13/2022
tbd	Petition for Approval of Extreme Cold Weather (phase 1)	10/31/2022

Standards Committee Expectations

Approved by Standards Committee January 12, 2012

Background

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

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

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

Expectations of Standards Committee Members

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

Parliamentary Procedures

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

Motions

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

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

Notes on Motions

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

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

Voting

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