Agenda
Standards Committee Meeting

May 15, 2024 | 1:00 p.m.—3:00 p.m. Eastern

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Introduction and Chair's Remarks

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

Agenda Items

1. **Review May 15, 2024 Agenda - Approve - *Todd Bennett* (1 minute)**
2. **Consent Agenda – Approve/Inform - *Todd Bennett* (5 minutes)**
   a. March 20, 2024 Standards Committee Meeting Minutes* - **Approve**
   b. May 3, 2024 Standards Committee Executive Committee Meeting Minutes* - **Approve**
   c. Standards Committee Special Election Results – **Inform**
3. **Projects Under Development - Review**
   a. Project Tracking Spreadsheet - *Mike Brytowski* (10 minutes)
   b. Projected Posting Schedule - *Latrice Harkness* (5 minutes)
   c. Fast Track Project – *Soo Jin Kim* (5 minutes)
4. **Generator Owner and Generator Operator Definition Alignment Standard Authorization Request – Accept/Authorize/Authorize/Delegate - *Alison Oswald* (10 minutes)**
   a. Generator Owner and Generator Operator Definition Alignment Standard Authorization Request*
5. **Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 1: Modeling and Data Sharing Requirements Standard Authorization Request – Accept/Authorize/Assign – *Jamie Calderon* (10 minutes)**
   a. Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 1: Modeling and Data Sharing Requirements Standard Authorization Request*
6. **Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 2: IBR Model Validation Standard Authorization Request – Accept/Authorize/Assign – *Jamie Calderon* (10 minutes)**
   a. Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 2: IBR Model Validation Standard Authorization Request*

7. **Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 3: IBR Modeling Revision Standard Authorization Request – Accept/Authorize/Assign – *Jamie Calderon* (10 minutes)**
   a. Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 3: IBR Modeling Revision Standard Authorization Request*
8. **Project 2023-06 CIP-014 Risk Assessment Refinement – Authorize – *Alison Oswald* (10 minutes)**
   a. CIP-014-4*
   b. Implementation Plan*
9. **Project 2023-04 Modifications to CIP-003 – Inform – *Alison Oswald* (10 minutes)**
10. **Legal Update and Upcoming Standards Filings - Review - *Sarah Crawford* (5 minutes)**
11. **Informational Items – Enclosed**
    a. Standards Committee Expectations*
    b. 2024 SC Meeting Schedule
    c. 2024 Standards Committee Roster
    d. Highlights of Parliamentary Procedure*
12. **Adjournment**

*Background materials included.

Minutes
Standards Committee Meeting

T. Bennett, chair, called to order the meeting of the Standards Committee (SC or the Committee) on March 20, 2024, at 10:29 a.m. Central. D. Love called roll and determined the meeting had a quorum. The SC member attendance and proxy sheets are attached as Attachment 1.

NERC Antitrust Compliance Guidelines and Public Announcement
D. Love called attention to the NERC Antitrust Compliance Guidelines and the public meeting notice and directed questions to NERC's General Counsel, Sonia C. Rocha.

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

Review March 20, 2024 Agenda (agenda item 1)
P. Yost made a motion to amend the agenda by moving agenda item 9 before agenda item 5. The Committee approved the March 20, 2024 meeting agenda.

Consent Agenda (agenda item 2)
The Committee approved the February 21, 2024 Standards Committee Meeting Minutes.

Standards Committee Member Training (agenda item 3)
M. Brytowski reviewed the Project Tracking Spreadsheet. L. Harkness reviewed the Three-month outlook and the Project Posting Schedule.

Periodic Standards Committee Member Training (agenda item 4)
S. Crawford presented on the 2023 Standards Rules of Procedure Revisions. T. Bennett presented on the Standards Committee Charter Revisions. C. Castaneda presented on the 2024 Registration Rules of Procedure Revisions.

High Priority Project Updates (agenda item 5)
T. Ness provided an update on Project 2023-03 Internal Network Security Monitoring R. Kloecker provided an update on Project 2022-03 Energy Assurance with Energy-Constrained Resources.

Guidance Document for Management of Remanded Interpretations (agenda item 6)
A. Oswald provided an overview. M. Powell made a motion to approve the following revised Standards Resource Document as recommended by the Standards Committee Process Subcommittee.

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

Project 2020-20 Modifications to PRC-024 (Generator Ride-through) (agenda item 7)
A. Oswald provided an overview of the project background. V. Greaff made a motion to authorize an initial posting of proposed Reliability Standard(s) PRC-024-4, PRC-029-1, and the associated Implementation Plan for a 25-day formal comment period, with ballot pools formed in the first 10 days and parallel initial ballots and non-binding polls on the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), conducted during the last 10 days of the comment period.

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

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues (agenda item 8)
J. Calderon provided an overview of project background. P. Winston made a motion to authorize initial posting of proposed Reliability Standard PRC-030-1 and the associated Implementation Plan for a 25-day formal comment period, with ballot pools formed in the first 10 days and parallel initial ballots and non-binding polls on the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), conducted during the last 10 days of the comment period.

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

Project 2023-07 Transmission System Planning Performance for Extreme Weather (agenda item 9)
J. Calderon provided an overview of project background. A. Casuscelli made a motion to authorize initial posting of proposed Reliability Standard TPL-008-1 and its associated Implementation Plan for a 45-day formal comment period, with ballot pools formed in the first 30 days and parallel initial ballots and non-binding polls on the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), conducted during the last 10 days of the comment period.

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

Subcommittees Updates (agenda item 10)
M. Brytowski provided updates from the Project Management and Oversight Subcommittee. T. Brumfield provided updates from the Standards Committee Process Subcommittee. T. Bennett provided updates from the Standing Committees Coordinating Group. J. Calderon provided updates from the Reliability and Security Technical Committee. S. Kelly provided updates from the NERC Board of Trustees.

Legal Update and Upcoming Standards Filings (agenda item 11)
S. Crawford provided an update.

T. Bennett made an announcement that K. Feliks from Segment three has vacated his position and a special election will be held.

Adjournment
The meeting adjourned at 2:04 p.m. Central.

Standards Committee
2024 Segment Representatives

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

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

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

Minutes
Standards Committee Executive Committee Special Call

T. Bennett, chair, called to order the meeting of the Standards Committee Executive Committee (SCEC) on May 3, 2024, at 3:00 p.m. Eastern. D. Love called roll and determined the meeting had a quorum. The SCEC member attendance and proxy sheets are attached as Attachment 1.

NERC Antitrust Compliance Guidelines and Public Announcement
D. Love called attention to the NERC Antitrust Compliance Guidelines and the public meeting notice and directed questions to NERC's General Counsel, Sonia C. Rocha.

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

Review May 3, 2024 Agenda (agenda item 1)
The SCEC approved the May 3, 2024 meeting agenda.

Project 2022-03 Energy Assurance with Energy-Constrained Resources (agenda item 2)
A. Oswald provided an overview of the project background. T. Brumfield made a motion to authorize an initial posting of proposed Reliability Standard BAL-008-1 and the associated Implementation Plan for a 45-day formal comment period, with ballot pools formed in the first 30 days and parallel initial ballots and non-binding polls on the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), conducted during the last 10 days of the comment period.

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

Adjournment
The meeting adjourned at 3:10 p.m. Eastern.

Standards Committee Executive Committee

Segment and Terms	Representative	Organization	Proxy	Present (Member or Proxy)
Chair 2024-25	Todd Bennett Managing Director, Reliability Compliance & Audit Services	Associated Electric Cooperative, Inc.		y
Vice Chair 2024-25	Troy Brumfield Regulatory Compliance Manager	American Transmission Company		y
Segment 4-2023-24	Patti Metro Senior Grid Operations & Reliability Director	National Rural Electric Cooperative Associate		y
Segment 5-2024-25	Terri Pyle Utility Operational Compliance and NERC Compliance Office	Oklahoma Gas and Electric		n
Segment 7-2023-24	Venona Greaff Senior Energy Analyst	Occidental Chemical Corporation		y

Generator Owner and Generator Operator Definition Alignment

Action

- Accept the Generator Owner (GO) and Generator Operator (GOP) Definition Alignment Standard Authorization Request (SAR);
- Authorize posting of the SAR for 30-day informal comment;
- Authorize solicitation of the drafting team (DT) members; and
- Delegate to Standards Committee Executive Committee (SCEC) authority to act on the GO and GOP Definition Alignment SAR to appoint members, chair, and vice chair to the DT for this project as recommended by NERC Staff.

Background

The project will address concerns regarding the reliability impacts of inverter-based resources (IBRs) on the Bulk-Power System (BPS) that do not meet the current definition of Bulk Electric System (BES) and have not historically been required to be registered with NERC for compliance with the NERC Reliability Standards. Such concerns are discussed in detail in the Federal Energy Regulatory Commission (FERC) November 17, 2022 order in Docket No. RD22-4-000, in which FERC directed NERC to develop a work plan to address the registration of these IBRs in accordance with certain milestones and ensure that “they are registered and required to comply with applicable Reliability Standards within 36 months of the approval date of the work plan” [i.e. May 2026]. *See Registration of Inverter-Based Resources*, 181 FERC ¶ 61,124 (Nov. 17, 2022).

In March 2024, NERC proposed changes to its Rules of Procedure (ROP) registry criteria to include certain non-BES IBRs in the GOs and GOP categories. In its filing, NERC asked FERC to take action on the proposed registry criteria changes by mid-June 2024. Revising the GO and GOP definitions in the NERC Glossary of Terms to match any registry criteria changes approved by FERC will maintain consistency between the two sets of definitions and ensure previously unregistered IBRs will be subject to the NERC Reliability Standards and mitigate their impacts on the BPS.

Summary

NERC Staff recommends that the Standards Committee (SC) accept the SAR, authorize posting for a 30-day informal comment period, and authorize the solicitation of DT members.

Due to the time sensitive nature of FERC’s deadlines, as well as stakeholder feedback seeking more clarity on the timing and next steps for IBR standards activity following the registry criteria changes, NERC staff recommends the SC authorize the SCEC to take action on appointing the DT members consistent with the SCEC’s authority under Chapter 7 of the SC Charter. Delegating this action would allow the SCEC to appoint a drafting team soon after a FERC order on the ROP revisions and would allow the drafting team to begin its work right away. Should FERC not act on NERC’s proposed Rules of Procedure registry criteria changes in June 2024, NERC staff would bring the DT appointments to the regularly scheduled SC meeting in July 2024.

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:	Generator Owner and Generator Operator Definition Alignment		
Date Submitted:	April 25, 2024		
SAR Requester			
Name:	Alison Oswald		
Organization:	NERC		
Telephone:	404-275-9410	Email:	alison.oswald@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

What is the risk to the Bulk Electric System (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):
The project will address concerns regarding the reliability impacts of inverter-based resources (IBRs) on the Bulk-Power System that do not meet the current definition of Bulk Electric System (BES) and have not historically been required to be registered with NERC for compliance with the NERC Reliability Standards. Such concerns are discussed in detail in the Federal Energy Regulatory Commission (FERC) November 17, 2022 order in Docket No. RD22-4-000, in which FERC directed NERC to develop a work plan to address the registration of these IBRs and ensure their compliance with Reliability Standards by certain milestone dates. *See Registration of Inverter-Based Resources*, 181 FERC ¶ 61,124 (Nov. 17, 2022). In March 2024, NERC proposed changes to its Rules of Procedure registry criteria to include certain non-BES IBRs in the Generator Owner (GOs) and Generator Operator (GOP) categories. Revising the GO and GOP definitions in the NERC Glossary of Terms to match the registry criteria will ensure these previously

Requested information
unregistered IBRs will be subject to the NERC Reliability Standards and mitigate their impacts on the BPS.
Purpose or Goal (What are the reliability gap(s) or risk(s) to the BES being addressed, and how does this proposed project provide the reliability-related benefit described above?):
The goal of this project is to match the NERC Glossary of Terms definitions of Generator Owner and Generator Operator with the revised definitions contained in the Rules of Procedure registry criteria for Generator Owner and Generator Operator.
Project Scope (Define the parameters of the proposed project):
Match the NERC Glossary of Terms with the definitions contained in the Rules of Procedure for Generator Owner and Generator Operator and propose an implementation plan for these definitions that is consistent with the November 17, 2022 FERC order.
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] of developing a new or revised Reliability Standard or definition, which includes a discussion of the risk and impact to reliability-of the BES, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The definitions of Generator Owner and Generator Operator in the NERC Rules of Procedure were revised in March 2024 to address the FERC directives from the November 17, 2022 order and NERC's work plan for implementing that order. These revisions were filed with FERC March 19, 2024; NERC requested expedited action by June 2024. The NERC Glossary of Terms should be revised to match the definitions that FERC approves in the Rules of Procedure registry criteria. This team should also develop an implementation plan for applicable standards consistent with FERC's November 17, 2022 IBR Registration order. Standards that may be applicable following a definition change include the following: ▪BAL-001-TRE-2 [2] ▪IRO-010-5 ▪MOD-032-1 ▪PRC-012-2 ▪PRC-017-1 ▪TOP-003-6.1 ▪VAR-001-5 ▪VAR-002-4.1
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):

[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.
[2] The Drafting team should collaborate with NERC and Regional Entity staff in the review and implementation of this standard.

Requested information
The cost impact is unknown at this time. Updating the GO/GOP definitions in conjunction with the NERC Registry Criteria will ensure that new entities are registered as GOs or GOPs and must be compliant with NERC Reliability Standards.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
This project will impact current non-BES IBRs with aggregate nameplate capacity greater than or equal to 20 MVA connected at a voltage greater than or equal to 60kv.
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 NERC Rules of Procedure Appendix 5A:
Generator Owner, Generator Operator will be the primary affected entities. However, other entities have responsibilities with respect to GOs/GOPs under the above-listed standards (e.g. Reliability Coordinator, Balancing Authority, Transmission Operator, Transmission Planner, Planning Coordinator, Resource Planner, Transmission Service Provider).
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 Rules of Procedure changes including the new GO/GOP registry criteria definitions went through a formal comment process where input was solicited from industry before the final revisions. Additional information can be found here.
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)?
None
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 with the benefits of using them.
None. The Glossary definitions of Generator Owner/Generator Operator must match those in the Rules of Procedure registry criteria to avoid conflict and confusion.

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.

[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	
☐	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
n/a	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
Risk Tracking.	
☒ Grid Transformation ☐ Resilience/Extreme Events	☐ Energy Policy ☐ Critical Infrastructure Interdependencies
☐ Security Risks	

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
5	August 14, 2023	Standards Development Staff	Updated template as part of Standards Process Stakeholder Engagement Group

Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 1: Modeling and Data Sharing Requirements

Action

- Accept the Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 1: Modeling and Data Sharing Requirements Standard Authorization Request (SAR);
- Authorize posting of the SAR for a 30-day informal comment period;
- Assign the SAR to the NERC Project 2022-02 Modifications to TPL-001-1-5.1 and MOD-032-1; and
- Authorize solicitation of nominations to supplement the drafting team.

Background

FERC Order No. 901 – Milestone 3, Part 1: Modeling and Data Sharing Requirements SAR addresses regulatory directives from the NERC Standards Development Work Plan to respond to FERC Order No. 901. This SAR is intended to establish new or revised Reliability Standards to ensure the usage of a uniform framework for data sharing and model development. This uniform framework is to ensure the directives of Order No. 901 can be effectively met to ensure usage of generic model types for IBR in the Interconnection-wide models. This SAR also builds mechanisms to allow equipment-specific models, if approved and as needed for model quality, to facilitate model changes as a result of the Milestone 2, 3, and 4 directives that evaluate performance of IBR. As those evaluations of performance may necessitate some form of corrective action, models changes based on performance must be consistently implemented and communicated so that future evaluations of performance are holistically consistent.

Revisions must ensure modeling revisions from other IBR performance requirements in other 901-related projects will utilize the uniform framework. For instance, performance of IBR during an event (grid disturbance) are identified and corrected within Milestone 2 of FERC Order No. 901. Evaluated performance within new PRC-029 or PRC-030 may necessitate some form of change to how specific IBR are represented in the model; as the IBR should be modeled based on how it performs during a disturbance or and new/changed equipment as a result of failing to ride through. However, any requisite changes to model data as a result of correcting IBR performance, must be communicated through a uniform model framework to assure all impacted entities and users of the approved models are adequately informed and provided updated models (as developed within this project). Similarly, revisions to model validation being drafted by another project who will be assigned the Milestone 3 Part 2 SAR, must also assure entities follow the uniform model framework established here. This SAR, Milestone 3 Part 1, will establish the uniform framework for data sharing and model development of future Order No. 901 related projects that will utilize performance data.

This SAR also includes new requirements for data aggregation estimation and data sharing of aggregated data for generation resources not registered by NERC. The drafting team will develop or modify existing Reliability Standards to establish data aggregation methods for unregistered IBR and IBR-DER, such that planners and operators have sufficient data to effectively plan and operate the system. This includes estimation techniques for unregistered IBR and IBR-DER (i.e., distribution-connected IBR) that are not BES but have demonstrated impact to BES facilities per FERC Order No. 901. Assets to be included as part of the revisions to the Compliance Registry criteria (“category 2 type assets”) are considered ‘”registered IBR” and not subject to the SAR objectives related to aggregated data or estimation methods. NERC must file the Reliability Standards or definitions developed under Milestone 3 by November 4, 2025.

As this SAR includes anticipated revisions to data sharing for Interconnection-wide base case development, NERC recommends this SAR be assigned to the Project 2022-02 Modifications to TPL-001-1-5.1 and MOD-032-1 drafting team. At the September 21, 2022 meeting, the SC accepted the original SARs assigned to Project 2022-02 Modifications to TPL-001-5.1 and MOD-032-01. To date, the drafting team has proposed revisions to MOD-032, which were posted May 31, 2023 through July 14, 2023. An additional draft was posted October 6, 2023 through November 20, 2023.

Due to the regulatory deadliner requiring that these revisions be filed with FERC by November, 2025, NERC recommends that this project be prioritized as a High Priority project. No waivers to the Standard Processes Manual are being requested at this time.

Summary

NERC staff recommends the SC accept FERC Order No. 901 – Milestone 3, Part 1: Modeling and Data Sharing Requirements SAR; authorize the posting for a 30-day informal comment period; assign it to the NERC Project 2022-02 Modifications to TPL-001-1-5.1 and MOD-032-1; and authorize solicitation of nominations to supplement the drafting team.

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:	Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 1: Modeling and Data Sharing Requirements		
Date Submitted:	4/29/24		
SAR Requester			
Name:	Alex Shattuck, Jamie Calderon, JP Skeath		
Organization:	North American Electric Reliability Corporation (NERC)		
Telephone:	470-259-0109 (Alex Shattuck) 404-960-0568 (Jamie Calderon) 404-823-1365 (JP Skeath)	Email:	Alex.Shattuck@nerc.net Jamie.Calderon@nerc.net John.Skeath@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	
What is the risk to the Bulk Electric System (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
This Standards Authorization Request (SAR) is initiated by NERC, with consultation of the Reliability Security Technical Committee, to address directives issued by FERC in Order No. 901. FERC issued Order No. 901 on October 19, 2023, which includes directives on new or modified NERC Reliability Standard projects. FERC Order No. 901 addresses a wide spectrum of reliability risks to the grid from the application of inverter-based resources (IBRs); including both utility scale and behind-the-meter or distributed energy resources (DERs). Within the Order are four milestones that include sets of directives to NERC. In the Order, FERC has directed NERC to propose new or modified standards to mitigate reliability gaps in the current NERC Reliability Standards related to IBRs. Specifically, FERC directed NERC to develop new or modified			

Requested information
Reliability Standards to address the following four broad topic areas related to IBRs: (1) data sharing; (2) data and model validation; (3) planning and operational studies; and (4) performance. In January 2024, NERC filed the initial **Standards Development Work Plan in Response to FERC Order No. 901** (hereafter referred to as the "Work Plan"). A current version of the Work Plan will be maintained here. The Work Plan discusses how NERC will develop Reliability Standards within (Milestones 2-4) to meet FERC's filing deadlines. This Standard Authorization Request addresses Milestone 3 of the Work Plan, related to Reliability Standards for modeling and data sharing requirements to establish sufficient IBR model data and parameters to assure accurate representation of IBR performance within the models. Further, collaborative sharing of this information, and the utilization of this information throughout the lifecycle of IBRs will also be established. Milestone 3 of the Work Plan covers the development of data provisioning, parameters, and estimation requirements for IBRs. FERC Order No. 901 directives address three categories of IBR: (1) registered IBR, including sub-Bulk Electric System IBRs to be registered under NERC's revised Compliance Registry criteria; (2) unregistered IBR; and (3) IBR-DER, to distinguish registered bulk connected IBRs from unregistered bulk connected IBRs as well as the transmission connected IBRs from distribution-connected IBRs. To be clear, assets to be included as part of revisions to the Compliance Registry criteria ("category 2 type assets") are considered herein as '"registered IBR". NERC must file the Reliability Standards or definitions developed under Milestone 3 by November 4, 2025. As often discussed within NERC recommendations and publications, the current paradigm of modeling and data sharing leaves the bulk power system (BPS) at a higher than necessary risk for unexpected and undesired inverter-based resource (IBR) performance. Since 2016, approximately 15,000 MW of IBR have unexpectedly reduced output during NERC categorized disturbance events. None of the IBR facilities involved in these disturbances utilized models that could accurately represent the facility's performance during the disturbance event. These discrepancies between modeled and studied performance when compared to real-world performance are driven by current industry modeling practices and a dependence on generic IBR modeling throughout the lifecycle of the IBR facility. NERC Modeling Guidance [1] states that additional model types, namely manufacturer-specific user-written models, must be used for local reliability studies, during the interconnection process and following commissioning to validate as-built performance – as well as through ongoing validation of performance. The deficiencies within the current state of model quality are well documented. As required by FERC Order No. 901, the development of positive sequence models based on an approved (standard) library of model types must be built into Interconnection-wide cases. Revisions to data sharing expectations and the creation of a "NERC Approved Model Library" that allows the use of manufacturer-specific models in addition to standard library (generic) models in instances

[1] https://www.nerc.com/pa/RAPA/ModelAssessment/Documents/Dynamic%20Modeling%20Recommendations.pdf

Requested information
where generic modeling cannot represent the performance of the IBR are necessary to ensure BPS reliability through improvements to the inputs of current study practices.
Purpose or Goal (What are the reliability gap(s) or risk(s) to the Bulk Electric System (BES) being addressed, and how does this proposed project provide the reliability-related benefit described above?):
This SAR addresses specific pieces of the NERC filed Work Plan related to Milestone 3 and addresses the various industry comments to meet the regulatory directives of FERC Order No. 901. This project shall coordinate among other projects (i.e., act as a clearing house to tie directive language to standard revisions), develop standard language (i.e., perform the normal duties of a standard development Project), and build upon other Milestones from FERC Order No. 901 Standards Projects to meet regulatory deadlines (i.e., maintain agility based on how FERC Order No. 901 related Projects proceed to meet the directive deadlines). This Project will also address FERC Order No. 901 directives related to aggregation of data, parameters, and estimation methods to provide the Transmission Planner (TP) and Transmission Operator (TOP) with the estimate values, explanation for limitations on data availability, and the method used for all estimations. This project is intended to serve as a data sharing center point for many of the revisions being established within all of the 901-related projects. Performance of IBR during an event (grid disturbance) are identified and corrected within the Standards Development projects pertaining to Milestone 2 of the Work Plan. However, any requisite changes to model data as a result of correcting IBR performance, must be communicated through a uniform model framework to assure all impacted entities and users of the approved models are adequately informed and provided updated models (as developed within this project). Similarly, revisions to model validation being drafted by the drafting team assigned the Milestone 3 Part 2 SAR, must also assure entities follow the uniform model framework established here.
Project Scope (Define the parameters of the proposed project):
The FERC Order No. 901 directives assigned to this SAR are outlined in the Detailed Description section below. The project scope shall address all those directives, and should consider the following objectives during the standards development process: 1. Modify MOD-032 to require the usage of a “NERC-Approved Model Library” (Hereafter: “Model Library”) that contains acceptable (and unacceptable) models and recommendations to facilitate the exchange of neighboring entities’ respective planning and operation models and to be used in Interconnection-wide case creation and in other NERC Reliability Standards for IBR. a. This Model Library will be developed and maintained by NERC. Updates on the Model Library development will be coordinated with the Drafting Team. The Drafting Team may solicit feedback comments of the NERC process from industry as needed. b. The Model Library will be accessible to the general public. NERC will develop an open and transparent process for maintaining the library. c. The Model Library will be consistent with NERC’s published Dynamic Modeling Recommendations, primarily:

Requested information
i. Industry-approved library models are sufficient for use in Interconnection-wide base case creation and interconnection-wide studies; ii. For local reliability studies (e.g. performance during the interconnection process, model quality validation), equipment-specific models should be used if generic models from the Model Library cannot accurately represent the IBR. 2. Modify applicable Reliability Standards (e.g. MOD-032, TOP-003, and IRO-010) to require Planning Coordinators, Transmission Planners, Reliability Coordinators, Transmission Operators, and Balancing Authorities to ensure usage of a uniform framework that includes modeling criteria consistent with NERC's Dynamic Modeling Recommendations, a registered modeling designee, and necessary data exchange requirements. The framework must require: a. Data specification and notifications for the data necessary to develop interconnection-wide models and models for other reliability studies; i. Specifications must include provisions for new, modified, or changed equipment, ii. Specifications must include provisions for changes to an approved equipment-specific models, iii. Specifications must include provisions and a periodicity for exchanging estimated aggregated unregistered IBR and DER data. b. Data exchange of generic models from the Model Library for interconnection-wide model creation that most accurately reflect the behavior of each IBR during steady state, short-circuit, and dynamic conditions; c. A review and approval process for additional model types from the Model Library (other than generic model types) for other reliability studies; d. Data exchange of aggregated data, estimation methods, and documented limitations of the availability of accurate data for unregistered IBR and DER as developed by Transmission Owners and Distribution Providers in Item 4. 3. Modify MOD-032 to require Generator Owners (GO) and Transmission Owners (TO) to follow the uniform framework developed in Item 2, specifically; a. GO and TO of IBR must provide generic models from the Model Library for interconnection-wide model creation that most accurately reflect the behavior of each IBR during steady state, short-circuit, and dynamic conditions; b. GO and TO of IBR must provide sufficient documentation regarding technical limitations and any inaccuracies as justification for the use of additional equipment-specific models. i. For instance, a Corrective Action Plan created by a planner or operator to address model quality due to exceeded performance criteria (reference Milestone 3 Part 2 SAR), may necessitate usage of an equipment-specific model instead of a generic model from the Model Library.

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ii. For instance, studied discrepancies between the generic model and performance or the IBR demonstrated during the interconnection process may necessitate usage of an equipment-specific model instead of a generic model from the Model Library. iii. For instance, discrepancies between the generic model and performance of the IBR during a disturbance (i.e. from a post-event analysis) may necessitate usage of an equipment-specific model instead of a generic model from the Model Library. 4. Modify TOP-003 and IRO-010 to require Transmission Owners and Distribution Providers to establish and implement data aggregation methods for unregistered IBR and DER. These standards must address: a. An estimate of the modeling data and parameters of IBR-DERs and unregistered IBRs, b. An explanation of the limitations of the availability of accurate data, and c. The method used for all estimations. 5. The drafting team shall ensure that implementation plans for new or modified Reliability Standards related to Milestone 3 of the Work Plan are aligned and do not create a reliability gap during implementation.
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] of developing a new or revised Reliability Standard or definition, which includes a discussion of the risk and impact to reliability-of the BES, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The project scope above will need to account for the specific directive text in FERC Order 901 to be successful. The drafting team should consider the specific language in the FERC directives, as well as any comments in the underlying FERC Order No. 901 proceeding that FERC directed NERC to consider as part of the standard development process. **FERC Order 901 Directives Assigned to this SAR:** NERC will maintain a current version of NERC Standards Development's Work Plan to Address FERC Order No. 901 on the NERC website under [Reliability Standards Under Development](). Included in this Work Plan is a list of the directives in FERC Order No. 901 and their associated mapping of each SAR submitted by NERC. The Work Plan will be updated should any mapping of FERC directives be reassigned due to ongoing work in the various Standards Development Projects. As of April 1, 2024, this SAR will address the following FERC Order No. 901 directives, with the scope for this SAR emphasized in **bold** as appropriate: 1. "Second, by November 4, 2025, NERC must submit new or modified Reliability Standards addressing the interrelated directives concerning: (1) data sharing for registered IBRs,

[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.

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unregistered IBRs, and IBR-DERs in the aggregate; and (2) data and model validation for registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate." (P 7) 2. "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to provide IBR-specific modeling data and parameters (e.g., steady-state, dynamic, and short circuit modeling information ,and control settings for momentary cessation and ramp rates) that accurately represent the registered IBRs to their planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities that are responsible for planning and operating the Bulk-Power System." (P 76) 3. "Nevertheless, to support accurate modeling and performance, we direct NERC to consider during its standards development process AEU and ACP/SEIA's suggested data sharing requirements when developing the framework, criteria, and necessary data exchange requirements to meet the registered IBR data sharing directive." (P 77) 4. "As discussed in more detail in section IV.C of this final rule, we are also directing NERC to develop new or modified Reliability Standards that require the use of approved industry IBR models that accurately reflect the behavior of all IBRs during steady state, short-circuit, and dynamic conditions." (P78) 5. "Likewise, regarding CAISO's request that the Commission direct NERC to consider requiring registered IBRs to provide additional data, we agree that such data collections may be warranted, and direct NERC to consider through its standards development process whether additional IBR data points (e.g., telemetry collections or other automated platform integrations) are needed to further enhance real-time visibility of Bulk-Power System operations." (P 86) 6. "Specifically, as proposed in the NOPR, we direct NERC to submit to the Commission for approval one or more new or modified Reliability Standards that require: (1) transmission owners to provide to Bulk-Power System planners and operators modeling data and parameters for unregistered IBRs in their transmission owner areas that, individually or in the aggregate, materially affect the reliable operation of the Bulk-Power System and (2) distribution providers to provide to Bulk-Power System planners and operators modeling data and parameters for IBR-DERs in the aggregate in their distribution provider areas where the IBR-DERs in the aggregate materially affect the reliable operation of the Bulk-Power System." (P 102) 7. "Recognizing that there may be instances in which transmission owners are unable to gather adequate unregistered IBR modeling data and parameters to create and maintain unregistered IBR models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation." (P 104)

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8. "To support this data collection, we further direct NERC to consider commenters suggestions to implement a process or mechanism by which transmission owners would receive modeling data and parameters." (P 104) 9. "Accordingly, to account for instances in which distribution providers are unable to gather adequate modeling data and parameters of IBR-DERs to create and maintain IBR-DER models, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require that each distribution provider, if unable to gather accurate IBR-DERs data in the aggregate or unable to gather IBR-DERs data in the aggregate at all, provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation." (P 105) 10. "In support of above, we further direct NERC to consider commenters' suggestions to implement a process or mechanism by which distribution providers would receive modeling data and parameters." (P 105) 11. "For those areas with IBR-DERs that in the aggregate materially affect the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we direct NERC to determine the appropriate registered entity responsible for providing data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, or, when unable to gather such accurate IBR-DERs data, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by the IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and (4) the method used for estimation." (P 106) 12. "Regarding CAISO's concern regarding the potential "compliance trap" where planners and operators rely on third-party data and IRC's request that the final rule specify the data to be submitted by all IBRs (i.e., registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate) and transmission devices using similar technologies, we direct NERC to determine through its standards development process the minimum categories or types of data that must be provided to transmission planners, transmission operators, transmission owners, and distribution providers necessary to predict the behavior of all IBRs and to ensure that compliance obligations are clear." (P 108) 13. "As discussed in more detail in section IV.C of this final rule, we are also directing NERC to develop new or modified Reliability Standards that require the use of approved industry IBR models that accurately reflect the behavior of all IBRs during steady state, short-circuit, and dynamic conditions." (P 108) 14. "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require the use of approved industry generic

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library IBR models that accurately reflect the behavior of IBRs during steady state, short-circuit, and dynamic conditions when developing planning, operations, and interconnection-wide models." (P 122) 15. "We direct NERC to determine through its standards development process which nation-wide approved component models are needed to build IBR plant models for steady state, short-circuit, and dynamics studies." (P 124) 16. "Accordingly, we direct NERC to develop new or modified Reliability Standards that require the sole use of nation-wide approved component generic library models for system models to facilitate the exchange of neighboring entities' respective planning and operation models and to build interconnection-wide models." (P 125) 17. "**We also direct NERC to require** the generator owners of registered IBRs and **the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators (e.g., planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) dynamic models that accurately represent the dynamic performance of** registered and **unregistered IBRs, including momentary cessation and/or tripping, and all ride through behavior**." (P 141) 18. "Recognizing that there may be instances in which transmission owners are unable to gather accurate unregistered IBR modeling data and parameters to create and maintain accurate unregistered IBR dynamic models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas, dynamic models of unregistered IBRs using estimated data in accordance with this final rule's section IV.B.3 data sharing directives." (P 141) 19. "Further, we direct NERC to require distribution providers to provide to the planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities aggregated dynamic models that adequately represent the dynamic performance of IBR-DERs on their systems that in the aggregate have a material impact on the Bulk-Power System, including momentary cessation and/or tripping, and all ride through behavior (e.g., IBR-DERs in the aggregate modeled by interconnection requirements performance to represent different steady-state and dynamic behavior)." (P141) 20. "Recognizing that there may be instances in which distribution providers are unable to gather data that accurately represents IBR-DERs in the aggregate, we modify the NOPR proposal and direct NERC to include in the proposed new or modified Reliability Standards a requirement that the distribution provider, if unable to gather data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, provide to the Bulk-Power System planners and operators (i.e., the data recipients) a dynamic model using estimated data for IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, in accordance with this final rule's section IV.B.3 data sharing directives." (P 141)

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21. "Furthermore, we acknowledge that there may be areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider. Therefore, we modify the NOPR proposal and direct NERC to determine the appropriate registered entity responsible for providing adequate data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and to identify the registered entities for coordinating, verifying, and keeping up to date the respective dynamic models." (P 141) 22. "Finally, NERC must ensure that the proposed new or modified Reliability Standards account for the dynamic performance of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System." (P 141) 23. "Accordingly, we direct NERC to develop new or modified Reliability Standards that require the use of the DER_A model or successor models to represent the behaviors of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System at a sufficient level of fidelity for Bulk-Power System planners and operators to create valid planning and operations and interconnection-wide models and to be able to perform respective system studies." (P 146) 24. "**Furthermore, for those areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we modify the NOPR proposal to direct NERC to determine the appropriate registered entity responsible for the data and parameters of IBR-DERs in the aggregate** and to establish a process that requires identified registered entities to coordinate, validate, and keep up to date the system models." (P 157) 25. "**Specifically, we direct NERC to develop new or modified Reliability Standards that require planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities to establish for each interconnection a uniform framework with modeling criteria, a registered modeling designee, and necessary data exchange requirements both between themselves and with the generator owners, transmission owners, and distribution providers to coordinate the creation of transmission planning, operations, and interconnection-wide models (i.e., system models)** and the validation of each respective system model." (P 161) 26. "Further, we believe that there is a need to have all of the directed Reliability Standards effective and enforceable well in advance of 2030 and direct NERC to ensure that the associated implementation plans sequentially stagger the effective and enforceable dates to ensure an orderly industry transition for complying with the IBR directives in this final rule prior to that date." (P 226)
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The associated cost with implementation of a new standard is currently unknown, and the modifications necessary for each specific directive are also unknown though they are expected to vary based on DT outcome.

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):
IBRs connected to the transmission system.
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 NERC Rules of Procedure Appendix 5A:
This Project should contain appropriate members representing the following Functional Entities: Balancing Authority Distribution Provider Generator Owner Generator Operator Planning Coordinator Reliability Coordinator Transmission Owner Transmission Operator Transmission Planner Reliability Coordinator
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.
FERC Order No. 901 NERC Standards Development Work Plan in Response to FERC Order No. 901 Inverter-Based Resource Activities, Quick Reference Guide Distributed Energy Resource Activities, Quick Reference Guide IBR Registration Initiative, Quick Reference Guide
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)?
1. SARs: a. SAR titled: Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 2: IBR Model Validation b. SAR titled: Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 3: IBR Modeling Revision 2. Active Reliability Standards Projects: a. 2020-06 Verifications of Models and Data for Generators b. 2021-01 Modifications to MOD-025 and PRC-019 c. 2022-02 Modifications to TPL-001-5.1 and MOD-032-1 (NERC Standards Development recommends assigning the SAR to this active project) d. 2022-04 EMT Modeling

[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.

Requested information
e. 2023-05 Modifications to FAC-001 and FAC-002 f. 2023-08 Modifications of MOD-031 Demand and Energy Data
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 with the benefits of using them.

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

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
Risk Tracking.	
☐ Grid Transformation ☐ Resilience/Extreme Events	☐ Energy Policy ☐ Critical Infrastructure Interdependencies
☐ Security Risks	

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
5	August 14, 2023	Standards Development Staff	Updated template as part of Standards Process Stakeholder Engagement Group

Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 2: IBR Model Validation Standard Authorization Request

Action

- Accept the Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 2: IBR Model Validation Standard Authorization Request (SAR);
- Authorize posting of the SAR for a 30-day informal comment period;
- Assign the SAR to the NERC Project 2020-06 (Verifications of Models and Data for Generators); and
- Authorize solicitation of nominations to supplement the drafting team.

Background

FERC Order No. 901 – Milestone 3, Part 2: IBR Model Validation SAR addresses regulatory directives from NERC Standards Development Work Plan to respond to FERC Order No. 901. This SAR is intended to establish new or revised Reliability Standards to address FERC Order No. 901 directives related to modeling validation (and verification) activities by utilizing actual performance data, including performance of IBR performance during a disturbance. This will help ensure the facility's model(s) reflect(s) the in-service equipment throughout the lifecycle of the IBR facility. NERC must file the Reliability Standards or definitions developed under Milestone 3 by November 4, 2025.

As this SAR includes anticipated revisions to model validation for IBR, NERC recommends it be assigned to Project 2020-06 Verifications of Models and Data for Generators. The drafting team will need to prioritize changes for this SAR over currently assigned SARs to remove IBR from MOD-026 and MOD-027 as this holistic approach includes some form of ongoing quality review and corrections based on new performance-based validation. This is necessary to prevent duplicative model validation requirements that do not align with the performance-based objectives of the regulatory directives. A second phase proposed by this SAR to incorporate the uniform model framework revisions into FAC-002 to assure a consistent hoslitic approach for model data sharing is established throughout the lifespan of IBR. As regulatory directives included within this SAR must be addressed in revisions to Reliability Standards that must be filed with FERC by November, 2025, NERC also recommends that this project remain prioritized as a High Priority project. No waivers to the Standard Processes Manual are being requested at this time.

At the July 21, 2021 meeting, the Standards Committee (SC) accepted the orginal SAR assigned to Project 2020-06 Verifications of Models and Data for Generators. The drafting team has only proposed revisions to MOD-026 at this time. The initial draft was posted May 20, 2022 through July 6, 2022. An additional draft was posted November 21, 2022 through January 18, 2023. Another additional draft was posted June 7, 2023 through July 21, 2023. The drafting team has also posted new definitions for IBRs to assure alignment between other 901-related projects. The drafting team will post one more draft of revisions before being assigned this SAR and moving forward with revisions.

Summary

NERC staff recommends the SC accept the Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 2: IBR Model Validation SAR; authorize the posting for a 30-day informal comment period; assign it to the NERC Project 2020-06 Verifications of Models and Data for Generators; and authorize solicitation of nominations to supplement the drafting team.

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:	Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 2: IBR Model Validation		
Date Submitted:	4/29/24		
SAR Requester			
Name:	Alex Shattuck, Jamie Calderon, JP Skeath		
Organization:	North American Electric Reliability Corporation (NERC)		
Telephone:	470-259-0109 (Alex Shattuck) 404-960-0568 (Jamie Calderon) 404-823-1365 (JP Skeath)	Email:	Alex.Shattuck@nerc.net Jamie.Calderon@nerc.net John.Skeath@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	
What is the risk to the Bulk Electric System (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
This Standards Authorization Request (SAR) is initiated by NERC, with consultation of the Reliability Security Technical Committee, to address directives issued by the Federal Energy Regulatory Commission (FERC) in Order No. 901. FERC issued Order No. 901 on October 19, 2023, which includes directives on new or modified NERC Reliability Standard projects. FERC Order No. 901 addresses a wide spectrum of reliability risks to the grid from the application of inverter-based resources (IBRs); including both utility scale and behind-the-meter or distributed energy resources (DERs). Within the Order, are four milestones that include sets of directives to NERC. In the Order, FERC has directed NERC to propose new or modified standards to mitigate reliability gaps in the current NERC Reliability Standards related to IBRs. Specifically, FERC directed NERC to develop new or modified			

Requested information
Reliability Standards to address the following four broad topic areas related to IBRs: (1) data sharing; (2) data and model validation; (3) planning and operational studies; and (4) performance. In January 2024, NERC filed the initial **Standards Development Work Plan in Response to FERC Order No. 901** (hereafter referred to as the "Work Plan). A current version of the Work Plan will be maintained here. The Work Plan discusses how NERC will develop Reliability Standards within three tranches (Milestones 2-4) to meet FERC's filing deadlines. This Standard Authorization Request addresses Milestone 3 – Part 2 of the Work Plan, related to Reliability Standards for IBR data sharing and model validation. Milestone 3 of the Work Plan covers the development of data provisioning, parameters, and estimation requirements for IBRs. FERC Order No. 901 directives address three categories of IBR: (1) registered IBR, including sub-Bulk Electric System IBRs to be registered under NERC's revised Compliance Registry criteria; (2) unregistered IBR; and (3) IBR-DER, to distinguish registered bulk connected IBRs from unregistered bulk connected IBRs as well as the transmission connected IBRs from distribution-connected IBRs. NERC must file the Reliability Standards or definitions developed under Milestone 3 by November 4, 2025.
Purpose or Goal (What are the reliability gap(s) or risk(s) to the Bulk Electric System being addressed, and how does this proposed project provide the reliability-related benefit described above?):
This SAR addresses specific pieces of the NERC filed Work Plan related to Milestone 3 and addresses the various industry comments to meet the regulatory directives of FERC Order No. 901. This project shall coordinate among other projects (i.e., act as a clearing house to tie directive language to standard revisions), develop standard language (i.e., perform the normal duties of a standard development Project), and build upon other Milestones from FERC Order No. 901 Standards Projects to meet regulatory deadlines (i.e., maintain agility based on how FERC Order No. 901 related Projects proceed to meet the directive deadlines). Specifically, the drafting team will address FERC Order No. 901 directives related to modeling validation (and verification) activities by utilizing actual performance data. This will help ensure the facility's model(s) reflects the in-service equipment throughout the lifecycle of the IBR facility.
Project Scope (Define the parameters of the proposed project):
The FERC Order No. 901 directives assigned to this SAR are outlined in the Detailed Description section below. The project scope shall address all those directives, and should consider the following objectives during the standards development process: **Phase 1 Objectives:** 1. Either revise MOD-033 or create a new IBR model validation Reliability Standard to require model validation using actual performance data.   a. include a complete set of validation expectations using performance data (must include performance data of IBR during disturbances as well as other performance measures);

Requested information
b. leverages the most accurate and highest quality model type available (reference data sharing scope from Milestone 3 Part 1 SAR); c. ensure post-interconnection validations are not solely based on staged testing, but instead are periodically validated using performance data; d. be designed to follow and be able to leverage new performance validations expected to be done during the interconnection process (to be established in phase 2 of this SAR); e. include minimum criteria for performing validation (e.g., time, tolerance, impact); f. include some planner/operator flexibility in determining specific performance criteria – g. Require planner and operators to communicate any performance criteria to Generator Owners; h. the DT should ensure any performance criteria established by the DT or by the planner and operators are risk-based and region-specific; i. the DT should consider other criteria may be created by planners and operators to demonstrate performance in upcoming revisions to Reliability Standards due to Milestone 4 projects (planning and operator studies using performance data); and j. the DT must require corrective action plans (CAPs) to be created by planners and operators that require the GO/TO to identify and improve model performance characteristics to align with performance. 2. Revise MOD-026 and MOD-027 to remove IBR from those Standards as this holistic approach includes some form of ongoing quality review and corrections based on new performance-based validation. 3. The drafting team shall ensure that implementation plans for new or modified Reliability Standards related to Milestone 3 of the Work Plan are aligned and do not create a reliability gap during implementation. **Phase 2 Objectives (not required as part of 901 Milestone 3 timeline)** 4. Either revise FAC-002 or create a new SAR to incorporate similar changes to IBR validation during the interconnection process or create a new IBR model validation standard to require model validation using actual performance data to validate model quality during the interconnection process. a. include a complete set of validation expectations using performance data, b. leverages the most accurate and highest quality model type available, c. ensure post-interconnection validations are not based on staged testing but instead are periodically validated using performance data, d. be designed to follow and be able to leverage new performance validations done during the interconnection process, e. include minimum criteria for performing validation (e.g., time, tolerance, impact), f. include some planner/operator flexibility in determining specific performance criteria, g. These are necessary to ensure that performance criteria are risk-based and region-specific h. These should consider parallel criteria developed for TPL-001 and the new PRC-030 to allow corrective action plans to be created by planners and operators that require the

Requested information
GO/TO to identify and improve model performance characteristics to align with performance.
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] of developing a new or revised Reliability Standard or definition, which includes a discussion of the risk and impact to reliability-of the BES, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The project scope above will need to account for the specific FERC Directive text in FERC Order 901 to be successful. The drafting team should consider the specific language in the FERC directives, as well as any comments in the FERC Order No. 901 proceeding that FERC directed NERC to consider as part of the standard development process. **FERC Order 901 Directives Assigned to this SAR:** NERC will maintain a current version of NERC Standards Development's Work Plan to Address FERC Order No. 901 on the NERC website under Reliability Standards Under Development. Included in this Work Plan is a list of the directives in FERC Order No. 901 and their associated mapping to each SAR submitted by NERC. The Work Plan will be updated should any mapping of FERC directives be reassigned due to ongoing work in the various Standards Development Projects. As of April 1, 2024, this SAR will address the following FERC Order No. 901 directives, with the scope for this SAR emphasized in **bold** as appropriate: 1. "**Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal to direct NERC to include in the new or modified Reliability Standards** technical criteria to require registered IBR generator owners to install disturbance monitoring equipment at their buses and elements, to require registered IBR generator owners to provide disturbance monitoring data to Bulk-Power System planners and operators for analyzing disturbances on the Bulk-Power System**, and to require Bulk-Power System planners and operators to validate registered IBR models using disturbance monitoring data from installed registered IBR generator owners' disturbance monitoring equipment**." (P85) 2. "With respect to NERC's recommendation for model benchmarking, we direct NERC to determine through its standards development process whether the development of benchmark cases to test model performance and a subsequent report comparing model performance are needed and at what periodicity." (P 126) 3. "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require the generator owners of registered IBRs, transmission owners that have unregistered IBRs on their system, and distribution providers that have IBR-DERs on their system to provide models that represent the dynamic behavior of these IBRs at a sufficient level of fidelity to provide to Bulk-Power System planners and operators

[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
to perform valid interconnection-wide, planning, and operational studies on a basis comparable to synchronous generation resources.” (P 140) 4. “We also direct NERC to require the generator owners of registered IBRs and the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators (e.g., planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) dynamic models that accurately represent the dynamic performance of registered and unregistered IBRs, including momentary cessation and/or tripping, and all ride through behavior.” (P 141) 5. “While we decline to include this level of detail in the directive to NERC, we nonetheless direct NERC to establish a standard uniform model verification process.” (P 143) 6. “Therefore, we direct NERC to define the model verification process and to require consistency among the model verification processes for existing Reliability Standards (e.g., FAC-002, MOD-026, and MOD-027) and any new or modified Reliability Standards.” (P 143) 7. “Moreover, although the Reliability Standards will apply to a different (albeit overlapping) set of entities than Order No. 2023, we believe consistency is needed between the complimentary proceedings and therefore direct NERC to include in the new or modified Reliability Standards a similar model verification process timeline consistent with FERC Order No. 2023 modeling deadline requirements.” (P 149) 8. “Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to submit new or modified Reliability Standards that require Bulk-Power System planners and operators to validate, coordinate, and update in a timely manner the system models by comparing all generator owner, transmission owner, and distribution provider verified IBR models (i.e., models of registered IBRs, unregistered IBRs, and IBR-DERs that in the aggregate have a material impact on the Bulk-Power System) and resulting system models against actual system operational behavior.” (P 156) 9. “**Furthermore, for those areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we modify the NOPR proposal to direct NERC to** determine the appropriate registered entity responsible for the data and parameters of IBR-DERs in the aggregate and to **establish a process that requires identified registered entities to coordinate, validate, and keep up to date the system models**.” (P 157) 10. “**Specifically, we direct NERC to develop new or modified Reliability Standards that require** planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities to establish for each interconnection a uniform framework with modeling criteria, a registered modeling designee, and necessary data exchange requirements both between themselves and with the generator owners, transmission owners, and distribution providers to coordinate the creation of transmission planning, operations, and interconnection-wide models (i.e., system models) and **the validation of each respective system model**.” (P 161)

Requested information
11. "Further, we direct NERC to include in the new or modified Reliability Standards a requirement for generator owners, transmission owners, and distribution providers to regularly update and communicate the verified data and models of registered IBRs, unregistered IBRs, and IBR-DERs by comparing their resulting models against actual operational behavior to achieve and maintain necessary modeling accuracy for inclusion of these resources in the system models." (P 161) 12. "For those areas with IBR-DERs in the aggregate that have a material impact on the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we modify the NOPR proposal to direct NERC to determine the appropriate registered entity responsible for the models of those IBR-DERs and to determine the registered entities responsible for updating, verifying, and coordinating models for IBR-DERs in the aggregate to meet the system models directives." (P 161) 13. "Further, we believe that there is a need to have all of the directed Reliability Standards effective and enforceable well in advance of 2030 and direct NERC to ensure that the associated implementation plans sequentially stagger the effective and enforceable dates to ensure an orderly industry transition for complying with the IBR directives in this final rule prior to that date." (P 226)
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The associated cost with implementation of a new standard is currently unknown. There may be potential cost savings if fewer reoccurring staged tests are performed.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
Inverter-Based Resources connected to the Bulk Power System (BPS) Distributed Energy Resources (DER-IBR), in aggregate
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 NERC Rules of Procedure Appendix 5A:
Transmission Planner Reliability Coordinator Distribution Provider Generator Owner and Generator Operator Transmission Owner and Transmission Operator
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.

[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
FERC Order No. 901 NERC Standards Development Work Plan in Response to FERC Order No. 901 Inverter-Based Resource Activities, Quick Reference Guide Distributed Energy Resource Activities, Quick Reference Guide IBR Registration Initiative, Quick Reference Guide
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)?
1. SARs: a. SAR titled: Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 1: Modeling and Data Sharing Requirements b. SAR titled: Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 3: IBR Modeling Revision 2. Active Reliability Standards Projects: a. 2020-06 Verifications of Models and Data for Generators (NERC Standards Development recommends assigning the SAR to this active project) b. 2021-01 Modifications to MOD-025 and PRC-019 c. 2022-02 Modifications to TPL-001-5.1 and MOD-032-1 d. 2022-04 EMT Modeling e. 2023-05 Modifications to FAC-001 and FAC-002 f. 2023-08 Modifications of MOD-031 Demand and Energy Data
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 with the benefits of using them.

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.

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
e.g., NPCC	Unknown at this time.

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
Risk Tracking.	
☐ Grid Transformation ☐ Resilience/Extreme Events	☐ Energy Policy ☐ Critical Infrastructure Interdependencies
☐ Security Risks	

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
5	August 14, 2023	Standards Development Staff	Updated template as part of Standards Process Stakeholder Engagement Group

Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 3: IBR Modeling Revision Standard Authorization Request

Action

- Accept the Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 3: IBR Modeling Revision Standard Authorization Request (SAR);
- Authorize posting of the SAR for a 30-day informal comment period; and
- Assign the SAR to the NERC Project 2021-01 Modifications to MOD-025 and PRC-019.

Background

The Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 3: IBR Modeling Revisions SAR does not directly address regulatory directives from NERC Standards Development Work Plan to respond to FERC Order No. 901. The SAR is intended to modify Reliability Standards within the scope of current Project 2021-01 Modifications to MOD-025 and PRC-019 to ensure that obligations to conduct model validation for IBR are not duplicative in nature or create competing expectations for IBR to conduct verification/validation of model data for IBR. As revisions to address model validation and improving quality will be fully addressed by the drafting team assigned to this SAR, it requires an adjustment of scope to remove IBR from the applicability of affected Reliability Standards.

NERC must file the Reliability Standards or definitions developed under Milestone 3 by November 4, 2025.

Since this SAR includes revisions to active projects currently revising modeling Standards not consistent with the performance-based model validation requirements directed in FERC Order No. 901, NERC recommends it be assigned to Project 2021-01 Modifications to MOD-025 and PRC-019. As regulatory directives included within this SAR must be addressed in revisions to Reliability Standards that must be filed with FERC by November, 2025, NERC also recommends that this project be prioritized as a High Priority project. No waivers to the Standard Processes Manual are being requested at this time.

At the December 15, 2021 meeting, the Standards Committee (SC) accepted the orginal SARs assigned to Project 2021-01 Modifications to MOD-025 and PRC-019. The drafting team has only proposed revisions to both MOD-025 and PRC-019. The initial drafts were posted November 4, 2022 through November 17, 2022. Additional drafts were posted April 25, 2023 through June 8, 2023.

Summary

NERC staff recommends the SC accept the Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 3: IBR Modeling Revisions SAR; authorize posting for a 30-day informal comment period; and assign it to NERC Project 2021-01 Modifications to MOD-025 and PRC-019.

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:	Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 3: IBR Modeling Revision		
Date Submitted:	4/29/2024		
SAR Requester			
Name:	Alex Shattuck, Jamie Calderon, JP Skeath		
Organization:	North American Electric Reliability Corporation (NERC)		
Telephone:	470-259-0109 (Alex Shattuck) 404-960-0568 (Jamie Calderon) 404-823-1365 (JP Skeath)	Email:	Alex.Shattuck@nerc.net Jamie.Calderon@nerc.net John.Skeath@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	
What is the risk to the Bulk Electric System (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
This Standards Authorization Request (SAR) is initiated by NERC, with consultation of the Reliability Security Technical Committee, to address directives issued by the Federal Energy Regulatory Commission (FERC) in Order No. 901. FERC issued Order No. 901 on October 19, 2023, which includes directives on new or modified NERC Reliability Standard projects. FERC Order No. 901 addresses a wide spectrum of reliability risks to the grid from the application of inverter-based resources (IBRs); including both utility scale and behind the-meter or distributed energy resources (DERs). Within the Order, are four milestones that include sets of directives to NERC. In Order 901, the Federal Energy Regulatory Commission ("FERC") has directed NERC to propose new or modified standards to mitigate reliability gaps in the current NERC Reliability Standards related to IBRs. Specifically, FERC			

Requested information
directed NERC to develop new or modified Reliability Standards to address the following four broad topic areas related to IBRs: (1) data sharing; (2) data and model validation; (3) planning and operational studies; and (4) performance. In January 2024, NERC filed the initial **Standards Development Work Plan in Response to FERC Order No. 901** (hereafter referred to as the "Work Plan). A current version of the Work Plan will be maintained here. The Work Plan discusses how NERC will develop Reliability Standards within three tranches (Milestones 2-4) to meet FERC's filing deadlines. This Standard Authorization Request addresses Milestone 3 – Part 4 of the Work Plan, related to modifying other Reliability Standards that involve model validation or verification for IBR to remove duplicative model validation requirements. Milestone 3 of the work plan covers the development of data provisioning, parameters, and estimation requirements for IBRs. FERC Order No. 901 directives address three categories of IBR: (1) registered IBR, including sub-Bulk Electric System IBRs to be registered under NERC's revised Compliance Registry criteria; (2) unregistered IBR; and (3) IBR-DER, to distinguish registered bulk connected IBRs from unregistered bulk connected IBRs as well as the transmission connected IBRs from distribution-connected IBRs. This SAR does not pertain to specific directives in FERC Order No. 901 directly, rather it is intended to complement the work proposed by the SAR titled **Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 2: IBR Model Validation**.
Purpose or Goal (What are the reliability gap(s) or risk(s) to the Bulk Electric System being addressed, and how does this proposed project provide the reliability-related benefit described above?):
All FERC directives associated with Milestone 3 of **NERC Standards Development Work Plan to Address FERC Order No. 901** are addressed by the other three SARs submitted by NERC. Most relevant to this SAR is the SAR titled: **Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 2: IBR Model Validation**. The **IBR Model Validation SAR** includes a holistic set of objectives and scope intended to address validation of IBR model and assure a robust approach to model quality improvement. As revisions to address model validation and improving quality will be addressed by the drafting team assigned the **IBR Model Validation SAR**, other active projects that are addressing IBR model data validation/verification must adjust their Reliability Standard Project scope to remove IBR from the applicability of affected Reliability Standards. The purpose of this project is to ensure that obligations to conduct model validation for IBR are not duplicative in nature or create competing expectations for IBR to conduct verification/validation of model data for IBR. This drafting team should collaborate as needed with the drafting team for **Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 2: IBR Model Validation** to assure no gaps are introduced.
Project Scope (Define the parameters of the proposed project):
The Drafting Team shall address the following project objectives:

Requested information
1. NERC Standards Development recommends assigning this SAR to the active **Project 2021-01 Modifications to MOD-025 and PRC-019**. If assigned to that project, the drafting team shall remove inverter-based resources from the scope of applicability for MOD-025-2 and PRC-019-2. If assigned to another project, the drafting team shall coordinate with the drafting team of **Project 2021-01 Modifications to MOD-025 and PRC-019** to accomplish this objective. 2. Coordinate with the drafting team of Project **2020-06 Verifications of Models and Data for Generators** to ensure removal of inverter-based resources from the applicability of MOD-026-1 and MOD-027-1. 3. The drafting team shall ensure that implementation plans for new or modified Reliability Standards related to Milestone 3 of the Work Plan are aligned and do not create a reliability gap during implementation.
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] of developing a new or revised Reliability Standard or definition, which includes a discussion of the risk and impact to reliability-of the BES, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The project scope above will need to account for the specific FERC directive text in FERC Order 901 to be successful. The drafting team should consider the specific language in the FERC directives, as well as any comments in FERC Order No. 901 proceeding that FERC directed NERC to consider as part of the standard development process. **FERC Order 901 Directives Assigned to this SAR:** NERC will maintain a current version of NERC Standards Development's Work Plan to Address FERC Order No. 901 on the NERC website under [Reliability Standards Under Development](). Included in this Work Plan, is a list of the directives in FERC Order No. 901 and their associated mapping to each SAR submitted by NERC. The Work Plan will be updated should any mapping of FERC directives be reassigned due to ongoing work in the various Standards Development Projects. As of April 1, 2024, this SAR will address no specific directives from FERC Order No. 901. This SAR is necessary to assure that a single solution for model validation using performance data may be established within the Milestone 3 Part 2 drafting team and does not create duplicative requirements. Establishment of data sharing requirements, including the coordination of protection settings and generating resource must be established within Milestone 3 Part 1.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):

[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
The associated cost with implementation of a new standard is currently unknown, and the modifications necessary for each specific directive are also unknown though they are expected to vary based on SDT outcome.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
Inverter-based resources connected to the transmission system.
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 NERC Rules of Procedure Appendix 5A:
This Project should contain appropriate members representing the following Functional Entities: Balancing Authority Distribution Provider Generator Owner Generator Operator Planning Coordinator Reliability Coordinator Transmission Owner Transmission Operator Transmission Planner Reliability Coordinator
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.
FERC Order No. 901 NERC Standards Development Work Plan in response to FERC Order No. 901 Inverter-Based Resource Activities, Quick Reference Guide Distributed Energy Resource Activities, Quick Reference Guide IBR Registration Initiative, Quick Reference Guide
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)?
1. SARs: a. SAR titled: Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 1: Modeling and Data Sharing Requirements b. SAR titled: Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 2: IBR Model Validation 2. Active Reliability Standards Projects: a. 2020-06 Verifications of Models and Data for Generators

[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
b. 2021-01 Modifications to MOD-025 and PRC-019 (NERC Standards Development recommends assigning the SAR to this active project) c. 2022-02 Modifications to TPL-001-5.1 and MOD-032-1 d. 2022-04 EMT Modeling e. 2023-05 Modifications to FAC-001 and FAC-002 f. 2023-08 Modifications of MOD-031 Demand and Energy Data
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 with the benefits of using them.

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	Yes

Market Interface Principles	
access commercially non-sensitive information that is required for compliance with reliability standards.	

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
	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
Risk Tracking.	
☐ Grid Transformation ☐ Resilience/Extreme Events	☐ Energy Policy ☐ Critical Infrastructure Interdependencies
☐ Security Risks	

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
5	August 14, 2023	Standards Development Staff	Updated template as part of Standards Process Stakeholder Engagement Group

Project 2023-06 CIP-014 Risk Assessment Refinement

Action

Authorize initial posting of proposed Reliability Standard CIP-014-4 and the associated Implementation Plan for a 45-day formal comment period, with ballot pools formed in the first 30 days and parallel initial ballots and non-binding polls on the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), conducted during the last 10 days of the comment period.

Background

Due to an increase in reports of physical attacks on electric substations, the Federal Energy Regulatory Commission (FERC) issued an Order on December 15, 2022, in Docket No. RD23-2-000, that directed NERC to conduct a study to evaluate: (1) the adequacy of the Applicability criteria set forth in the Physical Security Reliability Standard CIP-014-3 (Physical Security Reliability Standard); (2) the required risk assessment set forth in the Physical Security Reliability Standard; and (3) whether a minimum level of physical security protections should be required for all Bulk-Power System transmission stations and substations and primary control centers. NERC was directed to submit a report within 120 days. On April 14, 2023, NERC submitted its findings and recommendations to FERC. In the report, NERC found that the language in Requirement R1 of CIP-014 should be refined to ensure that entities conduct effective risk assessments of their applicable substations. Specifically, the report identified that there were inconsistent approaches to performing the risk assessment due, largely, to a lack of specificity in the requirement language as to the nature and parameters of the risk assessment. Accordingly, NERC committed to initiate a Reliability Standards development project to evaluate changes to CIP-014 to provide additional clarity on the risk assessment. The result was the creation of Project 2023-06.

The goal of Project 2023-06 is to identify and physically protect those Transmission stations, Transmission substations, and their associated primary control centers that are critical to the reliable and secure operation of the BPS. Registered entity approaches for the risk assessment must be reasonably consistent and substantiated with sufficient technically based rationale. At the October 18, 2023 Standards Committee (SC) meeting, the SC appointed the chair, vice chair, and drafting team members to Project 2023-06 - CIP-014 Risk Assessment Refinement.

A Quality Review (QR) for this Project was performed from April 18 – 23, 2024. The QR team consisted of Lauren Perotti (NERC Legal), Jon Hoffman (NERC Legal), John Skeath (NERC Advanced System Analytics), Scott Klauminzer (City of Tacoma), Sarah Crawford (NERC Legal), Ellese Murphy (Duke Energy), Elizabeth Davis (PJM), Kristine Martz (EEI), Alain Rigaud (NERC Legal), and Alex Shattuck (NERC Engineering & Security Integration).

Summary

NERC staff recommends that the SC authorize initial posting of proposed Reliability Standard CIP-014-4 and the associated Implementation Plan for a 45-day formal comment period with ballot pools formed in the first 30 days and parallel initial ballots and non-binding polls on the VRFs and VSLs, conducted during the last 10 days of the comment period.

Standard Development Timeline

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

Description of Current Draft

CIP-014-4 is posted for a 45-day formal comment period with initial ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 21, 2023
SAR posted for comment	July 23, 2023 – August 24, 2023
Accepted Revised SAR	January 17, 2024

Anticipated Actions	Date
45-day formal or informal comment period with ballot	May 20, 2024 – July 5, 2024
45-day formal or informal comment period with additional ballot	August 2, 2024 – September 16, 2024
10-day final ballot	October 14, 2024 – October 23, 2024
Board adoption	December 12, 2024

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

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

Term(s):

None.

A. Introduction

1. **Title:** Physical Security
2. **Number:** CIP-014-4
3. **Purpose:** To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Transmission Owner.

   4.1.2. Transmission Operator.

   Exemption: Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Reliability Standard.

5. **Effective Date:** See Implementation Plan for CIP-014-4.

B. Requirements and Measures

R1. Each Transmission Owner shall establish and maintain a list of applicable Transmission station(s) and Transmission substation(s) for performing risk assessments in accordance with the criteria in Attachment 1. Each Transmission Owner shall: *[Violation Risk Factor: High; Time-Horizon: Long-term Planning]*

1.1. Consider all Transmission station(s) and Transmission substation(s) that are existing or planned to be in service within 36 months; and

1.2. Review the list every 36 months and update the list, if necessary.

1.3. If the Transmission Owner identifies no applicable Transmission station(s) and Transmission substation(s), then no additional actions are required to fulfill the remainder of the standard.

M1. Examples of evidence may include, but are not limited to, dated written or electronic documentation of the Transmission stations and Transmission substations (existing or planned to be in service within 36 months) that meet the criteria in Attachment 1 as specified in Requirement R1.

R2. Each Transmission Owner shall establish and implement documented criteria for identifying Transmission station(s) and Transmission substation(s) in proximity to those identified in Requirement R1, irrespective of ownership, that shall be included in the risk assessment. *[Violation Risk Factor: Medium; Time-Horizon: Long-term Planning]*

2.1. The criteria shall, at a minimum include the following:

2.1.1. Line-of-sight between multiple Transmission station or Transmission substation yards from a single site.

2.1.2. Ease of access from a common public roadway that exists between multiple Transmission station or Transmission substation yards.

2.1.3. The Transmission station or Transmission substation yards are in close enough proximity that a single event can impact multiple Transmission stations or Transmission substations.

M2. Examples of evidence may include, but are not limited to, dated written or electronic documentation of the criteria used to determine the Transmission station(s) and Transmission substation(s) in proximity to those identified in Requirement R1 and the list of groups of Transmission station(s) and Transmission substation(s) identified in Requirements R1 and R2.

R3. Each Transmission Owner shall have a documented risk assessment methodology for evaluating the loss of each Transmission station(s) and Transmission substation(s) identified as applicable. The methodology shall include, at a minimum, the following: *[Violation Risk Factor: Lower; Time-Horizon: Long-term Planning]*

3.1. Technical rationale for determining the amount of acceptable load loss, the amount of acceptable generation loss, and post-event response resulting in instability, uncontrolled separation, or Cascading within an Interconnection.

3.1.1. Load loss, generation loss, and post-event response within an Interconnection shall be evaluated, using at a minimum the following:

3.1.1.1. Steady state voltages

3.1.1.2. Transient voltage response

3.1.1.3. Thermal loading of Facilities

3.1.1.4. Relay loadability

3.1.1.5. Post-contingency voltage deviation

3.1.1.6. Rotor angle stability

3.1.1.7. Loss of IBR generation

3.1.1.8. Frequency exceeding generator limits

3.1.1.9. Frequency stability

3.1.1.10. Acceptable damping of oscillations

3.1.1.11. Cascading line tripping

3.1.1.12. Steady-state voltage stability

3.1.2. Technically supported thresholds for acceptable load loss and acceptable generation loss.

3.2. Analysis at System peak, Off-Peak Load, and other System conditions susceptible to instability, uncontrolled separation, or Cascading within an Interconnection shall be conducted in dynamic and steady state simulations.

3.2.1. Steady state analysis shall include the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event, including any tripped facilities from dynamic simulations.

3.2.2. A Transmission station or Transmission substation that is already identified as critical to the Interconnection in dynamic or steady state studies does not require any additional studies.

3.3. Analysis of fault simulations, as follows:

3.4. If the Transmission station(s) or Transmission substation(s) identified in accordance with Requirement R1 is a singular Transmission station or Transmission substation, then fault simulations shall include a bolted 3-phase fault at the highest voltage level bus.

3.5. If the Transmission station(s) or Transmission substation(s) identified in accordance with Requirement R2 includes more than one Transmission stations or Transmission substations, then fault simulations shall include simultaneous single-phase faults at the highest voltage level buses of each of the Transmission station(s) or Transmission substation(s).

3.6. Fault simulations shall assume the loss of communication and system protection at the Transmission station(s) or Transmission substation(s) studied under Requirement R3, Parts 3.4 and 3.5.

3.6.1. Delayed (remote) clearing times shall be used unless otherwise technically substantiated.

3.6.2. 3.6.2. Actual clearing times shall be used unless otherwise technically substantiated.

M3. Each Transmission Owner shall provide dated evidence, such as electronic or hard copies, of risk assessment methodology satisfying Requirement R3.

R4. Each Transmission Owner with jointly owned Transmission station(s) and Transmission substation(s) shall coordinate to determine and identify each entity's individual and joint responsibilities for performing any required risk assessments at least once every 36 calendar months. [VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]

M4. Examples of acceptable evidence may include, but are not limited to, dated documentation, such as meeting minutes, agreements, and e-mail correspondence, that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and assessments.

R5. Each Transmission Owner shall conduct a risk assessment, using the methodology established in Requirement R3, on each Transmission station(s) and Transmission substation(s) identified as applicable in accordance with Requirements R1, R2, and R4 at least once every 36 calendar months. *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

5.1. Transmission station(s) and Transmission substation(s) previously identified as critical do not require subsequent risk assessments if they continue to be classified as critical.

5.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation classified as critical.

M5. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment satisfying Requirement R5. For Requirement R5, Part 5.2, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation classified as critical.

R6. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R5. The verification may occur concurrent with or after the risk assessment performed under Requirement R5. [VRF: High; Time-Horizon: Long-term Planning]

6.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R5. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

6.1.1. A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or

6.1.2. 6.1.2. An entity that has transmission planning or analysis experience.

6.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R5, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R5 risk assessment.

6.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R5, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:

6.3.1. Modify its identification under Requirement R5 consistent with the recommendation; or

6.3.2. Document the technical basis for not modifying the identification in accordance with the recommendation.

6.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third party verification of the Requirement R5 risk assessment and satisfied all of the applicable provisions of Requirement R6, including, if applicable, documenting the technical basis for not modifying the identification in Requirements R1, R2, R3, R4 and R5 as specified under Part 6.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4.

R7. For a primary control center(s) identified by the Transmission Owner according to Requirement R5, Part 5.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R5, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R5, notify the Transmission Operator that has operational control of the primary control center of such identification and the date of completion of Requirement R5 . [VRF: Medium; Time-Horizon: Long-term Planning]

7.1. If a Transmission station or Transmission substation previously identified under Requirements R1, R2, R3, R4, and R5 and verified according to Requirement R6 is removed from the identification during a subsequent risk assessment performed according to Requirement R5 or a verification according to Requirement R6, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M7. Examples of acceptable evidence may include, but are not limited to, written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R7.

R8. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R5 and verified according to Requirement R6, and each Transmission Operator notified by a Transmission Owner according to Requirement R7, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R5 and verified according to Requirement R6. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

8.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

8.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

8.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M8. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R8.

R9. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R5 and verified according to Requirement R6, and each Transmission Operator notified by a Transmission Owner according to Requirement R7, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R6 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: [*Violation Risk Factor*: *High; Time-Horizon: Long-term Planning*]

9.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R8.

9.2. Law enforcement contact and coordination information.

9.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

9.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M9. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R6, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

R10. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R5 and verified according to Requirement R6, and each Transmission Operator notified by a Transmission Owner according to Requirement R7, shall have an unaffiliated third party review the evaluation performed under Requirement R8 and the security plan(s) developed under

Requirement R9. The review may occur concurrently with or after completion of the evaluation performed under Requirement R8 and the security plan development under Requirement R9. *[VRF: Medium; Time-Horizon: Long-term Planning]*

10.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.
- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.
- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

10.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R9. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R8 or the security plan(s) developed under Requirement R9.

10.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R8 or security plan(s) developed under Requirement R9, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or
- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

10.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M10. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R8 and the security plan(s) developed under Requirement R9 as specified in Requirement R10 including, if applicable, documenting the reasons for not modifying the evaluation or security plan(s) in accordance with a recommendation under Part 10.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 10.4.

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 t during an on-site visit to show that it was compliant for the full-time period since the last audit.

   The Transmission Owner and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation:

   The responsible entities shall retain evidence, as per Requirements R1 through R10, for three years.

   If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, 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.

   1.3. 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

	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The Transmission Owner identified a list of applicable Transmission station(s) or Transmission substation(s) per Attachment 1 but did so after 36 calendar months but less than or equal to 38 calendar months. OR The Transmission Owner identified a list of applicable substations but failed to identify less than or equal to 10% of the applicable Transmission station(s) or Transmission substation(s) per Attachment 1	The Transmission Owner identified a list of applicable Transmission station(s) or Transmission substation(s) per Attachment 1 but did so after 38 calendar months but less than or equal to 40 calendar months. OR The Transmission Owner identified a list of applicable substations but failed to identify more than 10% and less than or equal to 20% of the applicable Transmission station(s) or Transmission substation(s) per Attachment 1	The Transmission Owner identified a list of applicable Transmission station(s) or Transmission substation(s) per Attachment 1 but did so after 40 calendar months but less than or equal to 42 calendar months. OR The Transmission Owner identified a list of applicable substations but failed to identify more than 20% and less than or equal to 30% of the applicable Transmission station(s) or Transmission substation(s) per Attachment 1	The Transmission Owner failed to identify a list of applicable Transmission station(s) or Transmission substation(s) per Attachment 1. OR The Transmission Owner identified a list of applicable Transmission station(s) or Transmission substation(s) per Attachment 1 but did so after more than 42 calendar months. OR The Transmission Owner identified a list of applicable substations but failed to identify more than 30% of the applicable Transmission station(s) or Transmission substation(s) per Attachment 1

	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R2.			The Transmission Owner had insufficient documented criteria for determining when Transmission station(s) or Transmission substation(s) were in proximity for those identified in Requirement R1. OR The Transmission Owner failed to use the documented criteria to identify all Transmission station(s) or Transmission substation(s) in proximity.	The Transmission Owner did not have documented criteria to determine when Transmission station(s) or Transmission substation(s) were in proximity of those identified in Requirement R1. OR The Transmission Owner failed to use the documented criteria to identify which Transmission station(s) or Transmission substation(s) in proximity.
R3.	The Transmission Owner has a risk assessment methodology that failed to include one of the requirements listed in Requirement R3, Parts 3.1 through 3.6.	The Transmission Owner has a risk assessment methodology that failed to include two of the requirements listed in Requirement R3, Parts 3.1 through 3.6.	The Transmission Owner has a risk assessment methodology that failed to include three or more of the requirements listed in Requirement R3, Parts 3.1 through 3.6.	The Transmission Owner does not have a risk assessment methodology.

	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R4.	The Transmission Owner performed a risk assessment but did so after 36 calendar months but less than or equal to 38 calendar months. OR The Transmission Owner performed a risk assessment inconsistent with one of the methodology requirements listed in Requirement R3, Parts 3.1 through 3.6	The Transmission Owner performed a risk assessment but did so after 38 calendar months but less than or equal to 40 calendar months. OR The Transmission Owner performed a risk assessment inconsistent with two of the methodology requirements listed in Requirement R3, Parts 3.1 through 3.6 OR The Transmission Owner performed a risk assessment that was insufficient with respect to Requirement R4, Part 4.2.	The Transmission Owner performed a risk assessment inconsistent with three or more of the methodology requirements listed in Requirement R3, Parts 3.1 through 3.6 OR The Transmission Owner performed a risk assessment but failed to include the primary control center identified in Requirement R4, Part 4.3.	The Transmission Owner performed a risk assessment but did so after more than 42 calendar months.
R5.	The Transmission Owner performed a risk assessment but did so after 36 calendar months but less than or	The Transmission Owner performed a risk assessment but did so after 38 calendar months but	The Transmission owner performed a risk assessment but did so after 40 calendar months but	The Transmission Owner performed a risk assessment but did so after more than 42 calendar months.

	equal to 38 calendar months. OR The Transmission Owner performed a risk assessment inconsistent with one of the methodology requirements listed in Requirement R3, Parts 3.1 through 3.6	less than or equal to 40 calendar months. OR The Transmission Owner performed a risk assessment inconsistent with two of the methodology requirements listed in Requirement R3, Parts 3.1 through 3.6 OR The Transmission Owner performed a risk assessment that was insufficient with respect to Requirement R4, Part 4.2.	less than or equal to 42 calendar months. OR The Transmission Owner performed a risk assessment inconsistent with three or more of the methodology requirements listed in Requirement R3, Parts 3.1 through 3.6 OR The Transmission Owner performed a risk assessment but failed to include the primary control center identified in Requirement R4, Part 4.3.	

	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R6.	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4 but did so in more than 90 calendar days but less than or equal to100 calendar days following completion of Requirement R4; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4 and modified or documented the technical basis for not modifying its identification under Requirement R4 as required by Part 5.2 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4 but did so more than 100 calendar days but less than or equal to 110 calendar days following completion of Requirement R4; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4 and modified or documented the technical basis for not modifying its identification under Requirement R4 as required by Part 5.2 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4 but did so more than 110 calendar days but less than or equal to 120 calendar days following completion of Requirement R4; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4 and modified or documented the technical basis for not modifying its identification under Requirement R4 as required by Part 5.2 but did so more than 80 calendar days from completion of the third party verification; OR	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4 but did so more than 120 calendar days following completion of Requirement R4; OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R4; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4 but failed to implement procedures for protecting information per Part 5.2.

			The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4 but failed to modify or document the technical basis for not modifying its identification under R4 as required by Part 5.2.	

	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R7.	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R6 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R5; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R4 but did so	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R6 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R5; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R4 but did so	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R6 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R5; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R4 but did so	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R6 but did so more than 13 calendar days following the completion of Requirement R5; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control center identified in Requirement R4; OR

	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.	more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.	more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.	The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R4 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R4.

	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R8.	N/A	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4 but failed to consider one of Parts 7.1 through 7.3 in the evaluation.	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4 but failed to consider two of Parts 7.1 through 7.3 in the evaluation.	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4 but failed to consider Parts 7.1 through 7.3.

	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R9.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R5; OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4 and	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R5; OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4 and	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R5; OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4 and	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4 but did so more than 150 calendar days after completing the verification in Requirement R5; OR The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4 and verified according to Requirement R5.

	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	verified according to Requirement R5 but failed to include one of Parts 8.1 through 8.4 in the plan.	verified according to Requirement R5 but failed to include two of Parts 8.1 through 8.4 in the plan.	verified according to Requirement R5 but failed to include three of Parts 8.1 through 8.4 in the plan.	OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4 and verified according to Requirement R5 but failed to include Parts 8.1 through 8.4 in the plan.
R10.	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R7 and the security plan(s) developed under Requirement R8 but did so in more than	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R7 and the security plan(s) developed under Requirement R8 but did so in more than	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R7 and the security plan(s) developed under Requirement R8 but did so more than 110 calendar days but less than or equal to 120 calendar days;	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R7 and the security plan(s) developed under Requirement R8 in

	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	90 calendar days but less than or equal to 100 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R7 and the security plan(s) developed under Requirement R8 and modified or documented the reason for not modifying the security plan(s) as specified in Part 9.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.	100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R7 and the security plan(s) developed under Requirement R8 and modified or documented the reason for not modifying the security plan(s) as specified in Part 9.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.	OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R7 and the security plan(s) developed under Requirement R8 and modified or documented the reason for not modifying the security plan(s) as specified in Part 9.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R7 and the security plan(s) developed under Requirement R8 but did not document the reason for not modifying the	more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R7 and the security plan(s) developed under Requirement R8; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R7 and the security plan(s) developed under Requirement R8 but failed to implement procedures for protecting information per Part 9.4.

			security plan(s) as specified in Part 9.3.	

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

CIP-014-4 Implementation Plan

CIP-014-4 Technical Rationale Document

Version History

Version	Date	Action	Change Tracking
1	October 1, 2015	Effective Date	New
2	April 16, 2015	Revised to meet FERC Order 802 directive to remove “widespread”.	Revision
2	May 7, 2015	Adopted by the NERC Board of Trustees	
2	July 14, 2015	FERC Letter Order in Docket No. RD15-4-000 approving CIP-014-2	
3	January 19, 2022	Revised to remove Compliance Section 1.4	Revision
3	June 16, 2022	FERC Letter Order in Docket No.RD22-3-000 approving Modifications to CIP-014-3	Revision
3	June 16,2022	Effective Date	Revision
4	TBD	Revisions made by the Project 2023-06 drafting team	Revision

Attachment 1

Applicable Transmission station(s) or Transmission substation(s) are those that meet any of the following criteria:

1. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility but is part of the generation interconnection Facility.

2. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility but is part of the generation interconnection Facility.

2.1 Transmission station(s) or Transmission substation(s), that individually are not applicable but are applicable when combined based on physical adjacency per Requirement R2, based on aggregated weighting value criteria from **Table 1** are to be considered as applicable.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

3. Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

4. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

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

CIP-014-4 is posted for a 45-day formal comment period with initial ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 21, 2023
SAR posted for comment	July 23, 2023 – August 24, 2023
Accepted Revised SAR	January 17, 2024

Anticipated Actions	Date
45-day formal or informal comment period with ballot	May 20, 2024 – July 5, 2024
45-day formal or informal comment period with additional ballot	August 2, 2024 – September 16, 2024
10-day final ballot	October 14, 2024 – October 23, 2024
Board adoption	December 12, 2024

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

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

Term(s):

None.

A. Introduction

1. **Title:** Physical Security
2. **Number:** CIP-014-4~~3~~
3. **Purpose:** To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.
4. **Applicability:**

4.1. Functional Entities:

4.1.1 Transmission Owner. ~~that owns a Transmission station or Transmission substation that meets any of the following criteria:~~

~~**4.1.1.1** Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.~~

~~**4.1.1.2** Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.~~

~~Voltage Value of a Line~~	~~Weight Value per Line~~
~~less than 200 kV (not applicable)~~	~~(not applicable)~~
~~200 kV to 299 kV~~	~~700~~
~~300 kV to 499 kV~~	~~1300~~
~~500 kV and above~~	~~0~~

~~**4.1.1.3** Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or~~

~~Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.~~

~~**4.1.1.4** Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.~~

4.1.2 Transmission Operator.

Exemption: Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

5. Effective Dates:

See Implementation Plan for CIP-014-4~~2~~.

~~**6. Background:**~~

~~This Reliability Standard addresses the directives from the FERC order issued March 7, 2014, *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014), which required NERC to develop a physical security reliability standard(s) to identify and protect facilities that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.~~

B. Requirements and Measures

R1. Each Transmission Owner shall establish and maintain a list of applicable Transmission station(s) and Transmission substation(s) for performing risk assessments in accordance with the criteria in Attachment 1. Each Transmission Owner shall: *[Violation Risk Factor: High; Time-Horizon: Long-term Planning]*

1.1. Consider all Transmission station(s) and Transmission substation(s) that are existing or planned to be in service within 36 months; and

1.2. Review the list every 36 months and update the list, if necessary.

1.3. If the Transmission Owner identifies no applicable Transmission station(s) and Transmission substation(s), then no additional actions are required to fulfill the remainder of the standard.

M1. Examples of evidence may include, but are not limited to, dated written or electronic documentation of the Transmission stations and Transmission substations (existing or planned to be in service within 36 months) that meet the criteria in Attachment 1 as specified in Requirement R1.

R2. Each Transmission Owner shall establish and implement documented criteria for identifying Transmission station(s) and Transmission substation(s) in proximity to those identified in Requirement R1, irrespective of ownership, that shall be included in the risk assessment. . *[Violation Risk Factor: Medium; Time-Horizon: Long-term Planning]*

2.1. The criteria shall at a minimum include the following:

2.1.1. Line-of-sight between multiple Transmission station or Transmission substation yards from a single site.

2.1.2. Ease of access from a common public roadway that exists between multiple Transmission station or Transmission substation yards.

2.1.3. The Transmission station or Transmission substation yards are in close enough proximity that a single event can impact multiple Transmission stations or Transmission substations.

M2. Examples of evidence may include, but are not limited to, dated written or electronic documentation of the criteria used to determine the Transmission station(s) and Transmission substation(s) in proximity to those identified in Requirement R1 and the list of groups of Transmission station(s) and Transmission substation(s) identified in Requirements R1 and R2.

R3. Each Transmission Owner shall have a documented risk assessment methodology for evaluating the loss of each Transmission station(s) and Transmission substation(s) identified as applicable. The methodology shall include, at a minimum, the following: *[Violation Risk Factor: Lower; Time-Horizon: Long-term Planning]*

3.1. Technical rationale for determining the amount of acceptable load loss, the amount of acceptable generation loss, and post-event response resulting in instability, uncontrolled separation, or Cascading within an Interconnection.

3.1.1. Load loss, generation loss, and post-event response within an Interconnection shall be evaluated, using at a minimum the following:

3.1.1.1. Steady state voltages

3.1.1.2. Transient voltage response

3.1.1.3. Thermal loading of Facilities

3.1.1.4. Relay loadability

3.1.1.5. Post-contingency voltage deviation

3.1.1.6. Rotor angle stability

3.1.1.7. Loss of IBR generation

3.1.1.8. Frequency exceeding generator limits

3.1.1.9. Frequency stability

3.1.1.10. Acceptable damping of oscillations

3.1.1.11. Cascading line tripping

3.1.1.12. Steady-state voltage stability

3.1.2. Technically supported thresholds for acceptable load loss and acceptable generation loss.

3.2. Analysis at System peak, Off-Peak Load, and other System conditions susceptible to instability, uncontrolled separation, or Cascading within an Interconnection shall be conducted in dynamic and steady state simulations.

3.2.1. Steady state analysis shall include the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event, including any tripped facilities from dynamic simulations.

3.2.2. A Transmission station or Transmission substation that is already identified as critical to the Interconnection in dynamic or steady state studies does not require any additional studies.

3.3. Analysis of fault simulations, as follows:

3.4. If the Transmission station(s) or Transmission substation(s) identified in accordance with Requirement R1 is a singular Transmission station or

Transmission substation, then fault simulations shall include a bolted 3-phase fault at the highest voltage level bus.

3.5. If the Transmission station(s) or Transmission substation(s) identified in accordance with Requirement R2 includes more than one Transmission stations or Transmission substations, then fault simulations shall include simultaneous single-phase faults at the highest voltage level buses of each of the Transmission station(s) or Transmission substation(s).

3.6. Fault simulations shall assume the loss of communication and system protection at the Transmission station(s) or Transmission substation(s) studied under Requirement R3, Parts 3.4 and 3.5.

3.6.1. Delayed (remote) clearing times shall be used unless otherwise technically substantiated.

3.6.2. Actual clearing times shall be used unless otherwise technically substantiated.

M3. Each Transmission Owner shall provide dated evidence, such as electronic or hard copies, of risk assessment methodology satisfying Requirement R3.

R4. Each Transmission Owner with jointly owned Transmission station(s) and Transmission substation(s) shall coordinate to determine and identify each entity's individual and joint responsibilities for performing any required risk assessments at least once every 36 calendar months. *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

M4. Examples of acceptable evidence may include, but are not limited to, dated documentation, such as meeting minutes, agreements, and e-mail correspondence, that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and assessments.

R5. Each Transmission Owner shall conduct a risk assessment, using the methodology established in Requirement R3, on each Transmission station(s) and Transmission substation(s) identified as applicable in accordance with Requirements R1, R2, and R4 at least once every 36 calendar months. *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

5.1. Transmission station(s) and Transmission substation(s) previously identified as critical do not require subsequent risk assessments if they continue to be classified as critical.

5.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation classified as critical.

M5. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment satisfying Requirement R5. For Requirement R5, Part 5.2, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation classified as critical.

~~**R1.** Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]*~~

~~**1.1.** Subsequent risk assessments shall be performed:~~

- ~~At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or~~
- ~~At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.~~

~~**1.2.** The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.~~

~~**M1.** Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.~~

~~**R2.**~~**R6.** Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R5~~1~~. The verification may occur concurrent with or after the risk assessment performed under Requirement R5~~1~~. *[VRF: Medium; Time-Horizon: Long-term Planning]*

~~2.1.~~6.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or
- An entity that has transmission planning or analysis experience.

~~2.2.~~6.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R5~~1~~ risk assessment.

~~2.3.~~6.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R5~~1~~, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:

- Modify its identification under Requirement R5~~1~~ consistent with the recommendation; or
- Document the technical basis for not modifying the identification in accordance with the recommendation.

~~2.4.~~6.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6~~2~~. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third party verification of the Requirement R5~~1~~ risk assessment and satisfied all of the applicable provisions of Requirement R6~~2~~, including, if applicable, documenting the technical basis for not modifying the Requirement R1, R2, R3, R4 and R5 identification as specified under Part 6~~2~~.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6~~2~~.4.

~~R3.~~R7. For a primary control center(s) identified by the Transmission Owner according to Requirement R5~~1~~, Part 5~~1~~.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R5~~2~~, and b) is not under the operational control of the Transmission Owner: the

Transmission Owner shall, within seven calendar days following completion of Requirement R5~~2~~, notify the Transmission Operator that has operational control of the primary control center of such identification and the date of completion of Requirement R5~~2~~. *[VRF: Lower; Time-Horizon: Long-term Planning]*

~~3.1.~~7.1. If a Transmission station or Transmission substation previously identified under Requirement R1, R2, R3, R4, and R5 and verified according to Requirement R6~~2~~ is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R5~~2~~, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M7~~3~~. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R7~~3~~.

~~R4.~~R8. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R5~~1~~ and verified according to Requirement R6~~2~~, and each Transmission Operator notified by a Transmission Owner according to Requirement R7~~3~~, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R5~~1~~ and verified according to Requirement R6~~2~~. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

~~4.1.~~8.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

~~4.2.~~8.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

~~4.3.~~8.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M8~~4~~. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R8~~4~~.

~~R5.~~R9. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R5~~1~~ and verified according to Requirement R6~~2~~, and each Transmission Operator notified by a Transmission Owner according to Requirement R7~~3~~, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R6~~2~~ and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]*

~~5.1.~~9.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

~~5.2.~~9.2. Law enforcement contact and coordination information.

~~5.3.~~9.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

~~5.4.~~9.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M9~~5~~. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R6~~5~~, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

~~R6.~~R10. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R5~~1~~ and verified according to Requirement R6~~2~~, and each Transmission Operator notified by a Transmission Owner according to Requirement R7~~3~~, shall have an unaffiliated third party review the evaluation performed under Requirement R8~~4~~ and the security plan(s) developed under Requirement R9~~5~~. The review may occur concurrently with or after completion of the evaluation performed under Requirement R8~~4~~ and the security plan development under Requirement R9~~5~~. *[VRF: Medium; Time-Horizon: Long-term Planning]*

~~6.1.~~10.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified

Protection Professional (CPP) or Physical Security Professional (PSP) certification.

- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.
- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

~~6.2.~~10.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R9~~5~~. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R8~~4~~ or the security plan(s) developed under Requirement R9~~5~~.

~~6.3.~~10.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R8~~4~~ or security plan(s) developed under Requirement R9~~5~~, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or
- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

~~6.4.~~10.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M10~~6~~. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R8~~4~~ and the security plan(s) developed under Requirement R9~~5~~ as specified in Requirement R10~~6~~ including, if applicable, documenting the reasons for not modifying the evaluation or security plan(s) in accordance with a recommendation under Part 10~~6~~.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 10~~6~~.4.

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.

~~As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.~~

1.2. Evidence Retention:

The following evidence retention periods 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 CEA may ask an entity to provide other evidence during an on-site visit to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation.

The responsible entities shall retain ~~documentation as~~ evidence, as per Requirements R1 through R10, for three years.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, 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.

~~The CEA shall keep the last audit records and all requested and submitted subsequent audit records, subject to the confidentiality provisions of Section 1500 of the Rules of Procedure and the provisions of Section 1.4 below.~~

1.3. Compliance Monitoring and Enforcement Program~~Assessment Processes~~: 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.

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Violation Investigations~~

~~Self-Reporting~~

~~Complaints Text~~

Violation Severity Levels

~~2. Table of Compliance Elements~~

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-014-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
~~R1~~	~~Long-term Planning~~	~~High~~	The Transmission Owner identified a list of applicable Transmission station(s) or Transmission substation(s) per Attachment 1 but did so after 36 calendar months but less than or equal to 38 calendar months. OR The Transmission Owner identified a list of applicable substations but failed to identify less than or equal to 10% of the applicable Transmission	The Transmission Owner identified a list of applicable Transmission station(s) or Transmission substation(s) per Attachment 1 but did so after 38 calendar months but less than or equal to 40 calendar months. OR The Transmission Owner identified a list of applicable substations but failed to identify more than 10% and less than or equal to 20% of the applicable Transmission	The Transmission Owner identified a list of applicable Transmission station(s) or Transmission substation(s) per Attachment 1 but did so after 40 calendar months but less than or equal to 42 calendar months. OR The Transmission Owner identified a list of applicable substations but failed to identify more than 20% and less than or equal to 30% of the applicable Transmission station(s) or Transmission	The Transmission Owner failed to identify a list of applicable Transmission station(s) or Transmission substation(s) per Attachment 1. OR The Transmission Owner identified a list of applicable Transmission station(s) or Transmission substation(s) per Attachment 1 but did so after more than 42 calendar months. OR

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-014-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			station(s) or Transmission substation(s) per Attachment 1	station(s) or Transmission substation(s) per Attachment 1	substation(s) per Attachment 1	The Transmission Owner identified a list of applicable substations but failed to identify more than 30% of the applicable Transmission station(s) or Transmission substation(s) per Attachment 1
R2	~~Long-term Planning~~	~~Medium~~			The Transmission Owner had insufficient documented criteria for determining when Transmission station(s) or Transmission substation(s) were in proximity for those identified in Requirement R1. OR The Transmission Owner failed to use the documented criteria to identify all	The Transmission Owner did not have documented criteria to determine when Transmission station(s) or Transmission substation(s) were in proximity for those identified in Requirement R1. OR The Transmission Owner failed to use the documented

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-014-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Transmission station(s) or Transmission substation(s) in proximity.	criteria to identify which Transmission station(s) or Transmission substation(s) in proximity.
R3	~~Long-term Planning~~	~~Lower~~	The Transmission Owner has a risk assessment methodology that failed to include one of the requirements listed in Requirement R3, Parts 3.1 through 3.6.	The Transmission Owner has a risk assessment methodology that failed to include two of the requirements listed in Requirement R3, Parts 3.1 through 3.6.	The Transmission Owner has a risk assessment methodology that failed to include three or more of the requirements listed in Requirement R3, Parts 3.1 through 3.6.	The Transmission Owner does not have a risk assessment methodology.
R4	~~Operations Planning, Long-term Planning~~	~~Medium~~	The Transmission Owner performed a risk assessment but did so after 36 calendar months but less than or equal to 38 calendar months.	The Transmission Owner performed a risk assessment but did so after 38 calendar months but less than or equal to 40 calendar months.	The Transmission owner performed a risk assessment but did so after 40 calendar months but less than or equal to 42 calendar months.	The Transmission Owner performed a risk assessment but did so after more than 42 calendar months.

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-014-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The Transmission Owner performed a risk assessment inconsistent with one of the methodology requirements listed in Requirement R3, Parts 3.1 through 3.6	OR The Transmission Owner performed a risk assessment inconsistent with two of the methodology requirements listed in Requirement R3, Parts 3.1 through 3.6 OR The Transmission Owner performed a risk assessment that was insufficient with respect to Requirement R4, Part 4.2.	OR The Transmission Owner performed a risk assessment inconsistent with three or more of the methodology requirements listed in Requirement R3, Parts 3.1 through 3.6 OR The Transmission Owner performed a risk assessment but failed to include the primary control center identified in Requirement R4, Part 4.3.	
R5	~~Operations Planning, Long-term Planning~~	~~Medium~~	The Transmission Owner performed a risk assessment but did so after 36 calendar months but	The Transmission Owner performed a risk assessment but did so after 38 calendar months but	The Transmission owner performed a risk assessment but did so after 40 calendar months but	The Transmission Owner performed a risk assessment but did so after more than 42 calendar months.

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-014-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			less than or equal to 38 calendar months. OR The Transmission Owner performed a risk assessment inconsistent with one of the methodology requirements listed in Requirement R3, Parts 3.1 through 3.6	less than or equal to 40 calendar months. OR The Transmission Owner performed a risk assessment inconsistent with two of the methodology requirements listed in Requirement R3, Parts 3.1 through 3.6 OR The Transmission Owner performed a risk assessment that was insufficient with respect to Requirement R4, Part 4.2.	less than or equal to 42 calendar months. OR The Transmission Owner performed a risk assessment inconsistent with three or more of the methodology requirements listed in Requirement R3, Parts 3.1 through 3.6 OR The Transmission Owner performed a risk assessment but failed to include the primary control center identified in Requirement R4, Part 4.3.	
~~R1~~	~~Long-term Planning~~	~~High~~	~~The Transmission Owner performed an initial risk assessment but did~~	~~The Transmission Owner performed an initial risk assessment but did so more than~~	~~The Transmission Owner performed an initial risk assessment but did so more than~~	~~The Transmission Owner performed an initial risk assessment but did~~

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-014-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			~~so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date;~~ ~~OR~~ ~~The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk~~	~~two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date;~~ ~~OR~~ ~~The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a~~	~~four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date;~~ ~~OR~~ ~~The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk~~	~~so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment;~~ ~~OR~~ ~~The Transmission Owner failed to perform an initial risk assessment;~~ ~~OR~~ ~~The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled~~

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-014-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			~~assessment but did so after 30 calendar months but less than or equal to 32 calendar months;~~ ~~OR~~ ~~The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 60 calendar months but less than~~	~~subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months;~~ ~~OR~~ ~~The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 62 calendar months but less than~~	~~assessment but did so after 34 calendar months but less than or equal to 36 calendar months;~~ ~~OR~~ ~~The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 64 calendar months but less than~~	~~separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months;~~ ~~OR~~ ~~The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a risk assessment;~~

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-014-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			~~or equal to 62 calendar months.~~	~~or equal to 64 calendar months.~~	~~or equal to 66 calendar months;~~ ~~OR~~ ~~The Transmission Owner performed a risk assessment but failed to include Part 1.2.~~	~~OR~~ ~~The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months;~~ ~~OR~~ ~~The Transmission Owner that has not identified in its previous risk~~

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-014-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						~~assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.~~
R6~~2~~	~~Long-term Planning~~	~~Medium~~	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but less than or equal to 100 calendar days following completion of Requirement R4~~1~~;	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but less than or equal to 110 calendar days following completion of Requirement R4~~1~~;	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to 120 calendar days following completion of Requirement R4~~1~~; OR	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days following completion of Requirement R44~~1~~; OR

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-014-3)			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4~~1~~ and modified or documented the technical basis for not modifying its identification under Requirement R4~~1~~ as required by Part 5.2~~2.3~~ but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.	Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4~~1~~ and modified or documented the technical basis for not modifying its identification under Requirement R4~~1~~ as required by Part ~~2.3~~5.2 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4~~1~~ and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part ~~2.3~~ 5.2but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to modify or document the technical basis for not	The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R4~~1~~; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4~~1~~ but failed to implement procedures for protecting information per Part ~~2.4~~5.2.

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-014-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					modifying its identification under R1 as required by Part ~~2.3~~5.2.	
R7~~3~~	~~Long-term Planning~~	~~Lower~~	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R6~~3~~ but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R5~~2~~; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R6~~3~~ but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R5~~2~~; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R6~~3~~ but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R5~~2~~; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R4~~1~~ but	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R6~~3~~ but did so more than 13 calendar days following the completion of Requirement R5~~2~~; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control center identified in Requirement R4~~1~~;

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-014-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			identification in Requirement R4~~1~~ but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.	identification in Requirement R4~~1~~ but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.	did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.	OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R4~~1~~ but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R4~~1~~.

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-014-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R8 4	~~Operations Planning, Long-term Planning~~	~~Medium~~	N/A	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4~~1~~ but failed to consider one of Parts 7~~4~~.1 through 7~~4~~.3 in the evaluation.	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4~~1~~ but failed to consider two of Parts 7~~4~~.1 through 7~~4~~.3 in the evaluation.	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4~~1~~; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-014-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						primary control center(s) identified in Requirement R4~~1~~ but failed to consider Parts 7~~4~~.1 through 7~~4~~.3.
R9 ~~5~~	~~Long-term Planning~~	~~High~~	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R5~~2~~; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4~~1~~ but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R5~~2~~; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4~~1~~ but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R5~~2~~; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4~~1~~ but did so more than 150 calendar days after completing the verification in Requirement R5~~2~~; OR

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-014-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4~~1~~ and verified according to Requirement R5~~2~~ but failed to include one of Parts 8~~5~~.1 through 8~~5~~.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4~~1~~ and verified according to Requirement R5~~2~~ but failed to include two of Parts 8~~5~~.1 through 8~~5~~.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4~~1~~ and verified according to Requirement R5~~2~~ but failed to include three of Parts 8~~5~~.1 through 8~~5~~.4 in the plan.	The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R4~~1~~ and verified according to Requirement R5~~2~~. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-014-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						primary control center(s) identified in Requirement R4~~1~~ and verified according to Requirement R5~~2~~ but failed to include Parts 8~~5~~.1 through 8~~5~~.4 in the plan.
R10~~6~~	~~Long-term Planning~~	~~Medium~~	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R7~~4~~ and the security plan(s) developed under Requirement R8~~5~~ but did so in more than 90 calendar days but less than or equal to 100 calendar days; OR The Responsible Entity had an unaffiliated third	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R7~~4~~ and the security plan(s) developed under Requirement R8~~5~~ but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R7~~4~~ and the security plan(s) developed under Requirement R8~~5~~ but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R7~~4~~ and the security plan(s) developed under Requirement R8~~5~~ in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-014-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			party review the evaluation performed under Requirement R7~~4~~ and the security plan(s) developed under Requirement R8~~5~~ and modified or documented the reason for not modifying the security plan(s) as specified in Part 9~~6~~.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.	party review the evaluation performed under Requirement R7~~4~~ and the security plan(s) developed under Requirement R8~~5~~ and modified or documented the reason for not modifying the security plan(s) as specified in Part 9~~6~~.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.	under Requirement R7~~4~~ and the security plan(s) developed under Requirement R8~~5~~ and modified or documented the reason for not modifying the security plan(s) as specified in Part 9~~6~~.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R7~~4~~ and the security plan(s) developed under Requirement R5 but did not document the reason for not modifying the security	performed under Requirement R7~~4~~ and the security plan(s) developed under Requirement R8~~5~~; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R7~~4~~ and the security plan(s) developed under Requirement R8~~5~~ but failed to implement procedures for protecting information per Part 9~~6~~.4.

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-014-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					plan(s) as specified in Part 9~~6~~.3.	

Attachment 1:

Applicable Transmission station(s) or Transmission substation(s) are those that meet any of the following criteria:

1. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility but is part of the generation interconnection Facility.

2. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility but is part of the generation interconnection Facility.

2.1 Transmission station(s) or Transmission substation(s), that individually are not applicable but are applicable when combined based on physical adjacency per Requirement R2, based on aggregated weighting value criteria from **Table 1** are to be considered as applicable.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

3. Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

4. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

CIP-014-4 Implementation Plan

CIP-014-4 Technical Rationale Document

~~None.~~

Version History

Version	Date	Action	Change Tracking
1	October 1, 2015	Effective Date	New
2	April 16, 2015	Revised to meet FERC Order 802 directive to remove “widespread”.	Revision
2	May 7, 2015	Adopted by the NERC Board of Trustees	
2	July 14, 2015	FERC Letter Order in Docket No. RD15-4-000 approving CIP-014-2	
3	January 19, 2022	Revised to remove Compliance Section 1.4	Revision
3	June 16, 2022	FERC Letter Order in Docket No.RD22-3-000 approving Modifications to CIP-014-3	Revision
3	June 16,2022	Effective Date	Revision
4	TBD	Adopted by NERC Board of Trustees	Revision

~~Guidelines and Technical Basis~~

~~Section 4 Applicability~~

~~The purpose of Reliability Standard CIP-014 is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled~~

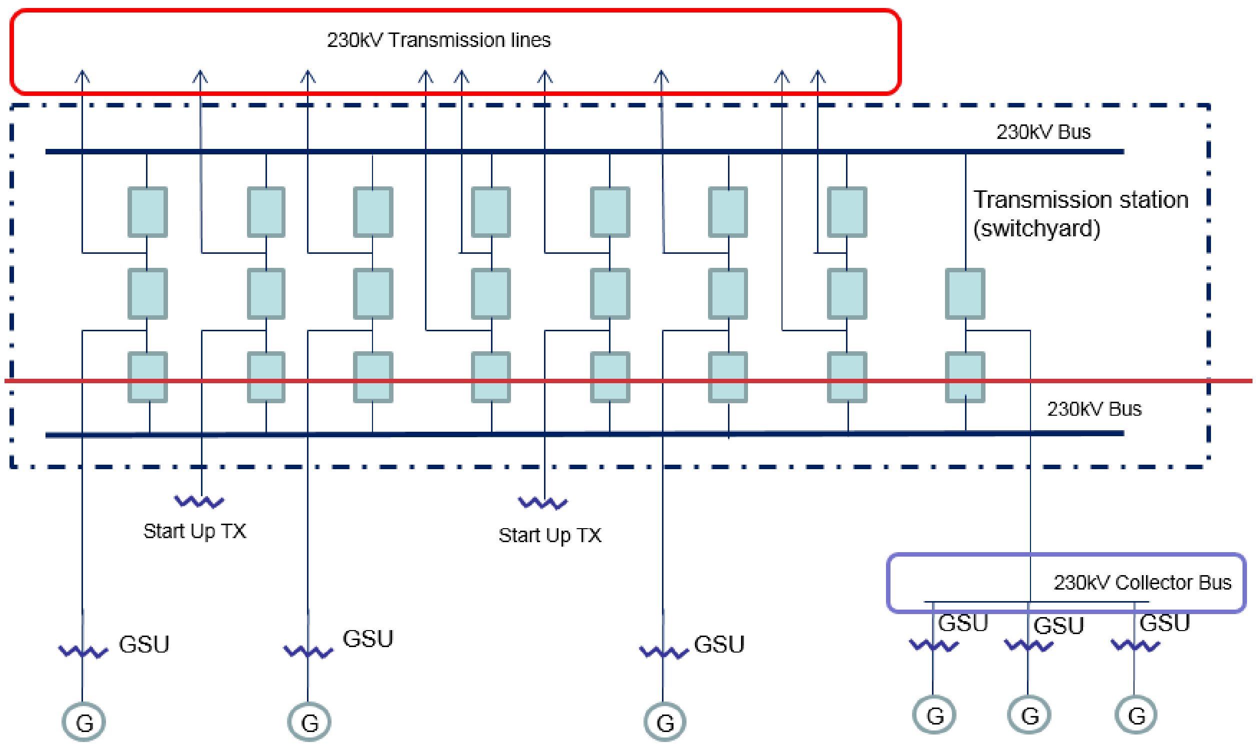
~~separation, or Cascading within an Interconnection. To properly include those entities that own or operate such Facilities, the Reliability Standard CIP-014 first applies to Transmission Owners that own Transmission Facilities that meet the specific criteria in Applicability Section 4.1.1.1 through 4.1.1.4. The Facilities described in Applicability Section 4.1.1.1 through 4.1.1.4 mirror those Transmission Facilities that meet the bright line criteria for "Medium Impact" Transmission Facilities under Attachment 1 of Reliability Standard CIP-002-5.1. Each Transmission Owner that owns Transmission Facilities that meet the criteria in Section 4.1.1.1 through 4.1.1.4 is required to perform a risk assessment as specified in Requirement R1 to identify its Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. The Standard Drafting Team (SDT) expects this population will be small and that many Transmission Owners that meet the applicability of this standard will not actually identify any such Facilities. Only those Transmission Owners with Transmission stations or Transmission substations identified in the risk assessment (and verified under Requirement R2) have performance obligations under Requirements R3 through R6.~~

~~This standard also applies to Transmission Operators. A Transmission Operator's obligations under the standard, however, are only triggered if the Transmission Operator is notified by an applicable Transmission Owner under Requirement R3 that the Transmission Operator operates a primary control center that operationally controls a Transmission station(s) or Transmission substation(s) identified in the Requirement R1 risk assessment. A primary control center operationally controls a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity. Only Transmission Operators who are notified that they have primary control centers under this standard have performance obligations under Requirements R4 through R6. In other words, primary control center for purposes of this Standard is the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation that is identified in Requirement R1 and verified in Requirement R2. Control centers that provide back-up capability are not applicable, as they are a form of resiliency and intentionally redundant.~~

~~The SDT considered several options for bright line criteria that could be used to determine applicability and provide an initial threshold that defines the set of Transmission stations and Transmission substations that would meet the directives of the FERC order on physical security (*i.e.*, those that could cause instability, uncontrolled separation, or Cascading within an Interconnection). The SDT determined that using the criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1 would provide a conservative threshold for defining which Transmission stations and Transmission substations must be included in the risk assessment in Requirement R1 of CIP-014. Additionally, the SDT concluded that using the CIP-002-5.1 Medium Impact criteria was appropriate because it has been approved by~~

~~stakeholders, NERC, and FERC, and its use provides a technically sound basis to determine which Transmission Owners should conduct the risk assessment. As described in CIP-002-5.1, the failure of a Transmission station or Transmission substation that meets the Medium Impact criteria could have the capability to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). The SDT understands that using this bright line criteria to determine applicability may require some Transmission Owners to perform risk assessments under Requirement R1 that will result in a finding that none of their Transmission stations or Transmission substations would pose a risk of instability, uncontrolled separation, or Cascading within an Interconnection. However, the SDT determined that higher bright lines could not be technically justified to ensure inclusion of all Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. Further guidance and technical basis for the bright line criteria for Medium Impact Facilities can be found in the Guidelines and Technical Basis section of CIP-002-5.1.~~

~~Additionally, the SDT determined that it was not necessary to include Generator Operators and Generator Owners in the Reliability Standard. First, Transmission stations or Transmission substations interconnecting generation facilities are considered when determining applicability. Transmission Owners will consider those Transmission stations and Transmission substations that include a Transmission station on the high side of the Generator Step-up transformer (GSU) using Applicability Section 4.1.1.1 and 4.1.1.2. As an example, a Transmission station or Transmission substation identified as a Transmission Owner facility that interconnects generation will be subject to the Requirement R1 risk assessment if it operates at 500kV or greater or if it is connected at 200 kV – 499kV to three or more other Transmission stations or Transmission substations and has an "aggregate weighted value" exceeding 3000 according to the table in Applicability Section 4.1.1.2. Second, the Transmission analysis or analyses conducted under Requirement R1 should take into account the impact of the loss of generation connected to applicable Transmission stations or Transmission substations. Additionally, the FERC order does not explicitly mention generation assets and is reasonably understood to focus on the most critical Transmission Facilities. The diagram below shows an example of a station.~~



~~Also, the SDT uses the phrase "Transmission stations or Transmission substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (switching stations or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.~~

~~On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014 when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards.~~

~~The language contained in the applicability section regarding the collector bus is directly copied from CIP-002-5.1, Attachment 1, and has no additional meaning within the CIP-014 standard.~~

~~Requirement R1~~

~~The initial risk assessment required under Requirement R1 must be completed on or before the effective date of the standard. Subsequent risk assessments are to be performed at least once every 30 or 60 months depending on the results of the previous risk assessment per~~

~~Requirement R1, Part 1.1. In performing the risk assessment under Requirement R1, the Transmission Owner should first identify their population of Transmission stations and Transmission substations that meet the criteria contained in Applicability Section 4.1.1. Requirement R1 then requires the Transmission Owner to perform a risk assessment, consisting of a transmission analysis, to determine which of those Transmission stations and Transmission Substations if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:~~

~~Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6~~

~~NERC EOP-004-2 reporting criteria~~

~~Area or magnitude of potential impact~~

~~The standard does not mandate the specific analytical method for performing the risk assessment. The Transmission Owner has the discretion to choose the specific method that best suites its needs. As an example, an entity may perform a Power Flow analysis and stability analysis at a variety of load levels.~~

~~Performing Risk Assessments~~

~~The Transmission Owner has the discretion to select a transmission analysis method that fits its facts and system circumstances. To mandate a specific approach is not technically desirable and may lead to results that fail to adequately consider regional, topological, and system circumstances. The following guidance is only an example on how a Transmission Owner may perform a power flow and/or stability analysis to identify those Transmission stations and Transmission substations that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. An entity could remove all lines, without regard to the voltage level, to a single Transmission station or Transmission substation and review the simulation results to assess system behavior to determine if Cascading of Transmission Facilities, uncontrolled separation, or voltage or frequency instability is likely to occur over a significant area of the Interconnection. Using engineering judgment, the Transmission Owner (possibly in consultation with regional planning or operation committees and/or ISO/RTO committee input) should develop criteria (e.g. imposing a fault near the removed Transmission station or Transmission substation) to identify a contingency or parameters that result in potential instability, uncontrolled separation, or~~

~~Cascading within an Interconnection. Regional consultation on these matters is likely to be helpful and informative, given that the inputs for the risk assessment and the attributes of what constitutes instability, uncontrolled separation, or Cascading within an Interconnection will likely vary from region-to-region or from ISO-to-ISO based on topology, system characteristics, and system configurations. Criteria could also include post-contingency facilities loadings above a certain emergency rating or failure of a power flow case to converge. Available special protection systems (SPS), if any, could be applied to determine if the system experiences any additional instability which may result in uncontrolled separation. Example criteria may include:~~

~~(a) Thermal overloads beyond facility emergency ratings;~~

~~(b) Voltage deviation exceeding ± 10%; or~~

~~(c) Cascading outage/voltage collapse; or~~

~~(d) Frequency below under-frequency load shed points~~

~~Periodicity~~

~~A Transmission Owner who identifies one or more Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection is required to conduct a risk assessment at least once every 30 months. This period ensures that the risk assessment remains current with projected conditions and configurations in the planned system. This risk assessment, as the initial assessment, must consider applicable planned Transmission stations and Transmission substations to be in service within 24 months. The 30 month timeframe aligns with the 24 month planned to be in service date because the Transmission Owner is provided the flexibility, depending on its planning cycle and the frequency in which it may plan to construct a new Transmission station or Transmission substation to more closely align these dates. The requirement is to conduct the risk assessment at least once every 30 months, so for a Transmission Owner that believes it is better to conduct a risk assessment once every 24 months, because of its planning cycle, it has the flexibility to do so.~~

~~Transmission Owners that have not identified any Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection are unlikely to see changes to their risk assessment in the Near-Term Planning Horizon. Consequently, a 60 month periodicity for completing a subsequent risk assessment is specified.~~

~~Identification of Primary Control Centers~~

~~After completing the risk assessment specified in Requirement R1, it is important to additionally identify the primary control center that operationally controls each Transmission station or Transmission substation that if rendered inoperable or damaged could result in instability,~~

~~uncontrolled separation, or Cascading within an Interconnection. A primary control center "operationally controls" a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker.~~

~~Requirement R2~~

~~This requirement specifies verification of the risk assessment performed under Requirement R1 by an entity other than the owner or operator of the Requirement R1 risk assessment.~~

~~A verification of the risk assessment by an unaffiliated third party, as specified in Requirement R2, could consist of:~~

~~Certifying that the Requirement R1 risk assessment considers the Transmission stations and Transmission substations identified in Applicability Section 4.1.1.~~

~~Review of the model used to conduct the risk assessment to ensure it contains sufficient system topology to identify Transmission stations and Transmission substations that if rendered inoperable or damaged could cause instability, uncontrolled separation, or Cascading within an Interconnection.~~

~~Review of the Requirement R1 risk assessment methodology.~~

~~This requirement provides the flexibility for a Transmission Owner to select from unaffiliated registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term unaffiliated means that the selected verifying entity cannot be a corporate affiliate (*i.e.,* the verifying or third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit.~~

~~The prohibition on registered entities using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. For instance, a U.S. federal power marketing agency may select as its verifier another U.S. federal agency to conduct its verification so long as the selected entity has transmission planning or analysis experience. Similarly, a Transmission Owner owned by a Canadian province can use a separate agency of that province to perform the verification. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.~~

~~Requirement R2 also provides that the "verification may occur concurrent with or after the risk assessment performed under Requirement R1." This provision is designed to provide the Transmission Owner the flexibility to work with the verifying entity throughout (*i.e.,* concurrent with) the risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could collaborate with their unaffiliated~~

~~verifying entity to perform the risk assessment under Requirement R1 such that both Requirement R1 and Requirement R2 are satisfied concurrently. The intent of Requirement R2 is to have an entity other than the owner or operator of the facility to be involved in the risk assessment process and have an opportunity to provide input. Accordingly, Requirement R2 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the risk assessment and subsequently has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the risk assessment.~~

~~Characteristics to consider in selecting a third party reviewer could include:~~

~~Registered Entity with applicable planning and reliability functions.~~

~~Experience in power system studies and planning.~~

~~The entity's understanding of the MOD standards, TPL standards, and facility ratings as they pertain to planning studies.~~

~~The entity's familiarity with the Interconnection within which the Transmission Owner is located.~~

~~With respect to the requirement that Transmission owners develop and implement procedures for protecting confidential and sensitive information, the Transmission Owner could have a method for identifying documents that require confidential treatment. One mechanism for protecting confidential or sensitive information is to prohibit removal of sensitive or confidential information from the Transmission Owner's site. Transmission Owners could include such a prohibition in a non-disclosure agreement with the verifying entity.~~

~~A Technical feasibility study is not required in the Requirement R2 documentation of the technical basis for not modifying the identification in accordance with the recommendation.~~

~~On the issue of the difference between a verifier in Requirement R2 and a reviewer in Requirement R6, the SDT indicates that the verifier will confirm that the risk assessment was completed in accordance with Requirement R1, including the number of Transmission stations and substations identified, while the reviewer in Requirement R6 is providing expertise on the manner in which the evaluation of threats was conducted in accordance with Requirement R4, and the physical security plan in accordance with Requirement R5. In the latter situation there is no verification of a technical analysis, rather an application of experience and expertise to provide guidance or recommendations, if needed.~~

~~Parts 2.4 and 6.4 require the entities to have procedures to protect the confidentiality of sensitive or confidential information. Those procedures may include the following elements:~~

~~Control and retention of information on site for third party verifiers/reviewers.~~

~~Only "need to know" employees, etc., get the information.~~

~~Marking documents as confidential~~

~~Securely storing and destroying information when no longer needed.~~

~~Not releasing information outside the entity without, for example, General Counsel sign-off.~~

~~Requirement R3~~

~~Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first completing the risk assessment specified by Requirement R1 and the verification specified by Requirement R2. Requirement R3 is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1 receive notice so that the Transmission Operator may fulfill the rest of the obligations required in Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include within the notice the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or as a result of the verification process under Requirement R2.~~

~~Requirement R4~~

~~This requirement requires owners and operators of facilities identified by the Requirement R1 risk assessment and that are verified under Requirement R2 to conduct an assessment of potential threats and vulnerabilities to those Transmission stations, Transmission substations, and primary control centers using a tailored evaluation process. Threats and vulnerabilities may vary from facility to facility based on any number of factors that include, but are not limited to, location, size, function, existing physical security protections, and attractiveness as a target.~~

~~In order to effectively conduct a threat and vulnerability assessment, the asset owner may be the best source to determine specific site vulnerabilities, but current and evolving threats may best be determined by others in the intelligence or law enforcement communities. A number of resources have been identified in the standard, but many others exist and asset owners are not limited to where they may turn for assistance. Additional resources may include state or local fusion centers, U.S. Department of Homeland Security, Federal Bureau of Investigations (FBI), Public Safety Canada, Royal Canadian Mounted Police, and InfraGard chapters coordinated by the FBI.~~

~~The Responsible Entity is required to take a number of factors into account in Parts 4.1 to 4.3 in order to make a risk-based evaluation under Requirement R4.~~

~~To assist in determining the current threat for a facility, the prior history of attacks on similarly protected facilities should be considered when assessing probability and likelihood of occurrence at the facility in question.~~

~~Resources that may be useful in conducting threat and vulnerability assessments include:~~

~~NERC Security Guideline for the Electricity Sector: Physical Security.~~

~~NERC Security Guideline: Physical Security Response.~~

~~ASIS International General Risk Assessment Guidelines.~~

~~ASIS International Facilities Physical Security Measure Guideline.~~

~~ASIS International Security Management Standard: Physical Asset Protection.~~

~~Whole Building Design Guide - Threat/Vulnerability Assessments.~~

~~Requirement R5~~

~~This requirement specifies development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.~~

~~Requirement R5 specifies the following attributes for the physical security plan:~~

~~Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.~~

~~Resiliency may include, among other things:~~

~~a. System topology changes,~~

~~b. Spare equipment,~~

~~c. Construction of a new Transmission station or Transmission substation.~~

~~While most security measures will work together to collectively harden the entire site, some may be allocated to protect specific critical components. For example, if protection from gunfire is considered necessary, the entity may only install ballistic protection for critical components, not the entire site.~~

~~Law enforcement contact and coordination information.~~

~~Examples of such information may be posting 9-1-1 for emergency calls and providing substation safety and familiarization training for local and federal law enforcement, fire department, and Emergency Medical Services.~~

~~A timeline for executing the physical security enhancements and modifications specified in the physical security plan.~~

~~Entities have the flexibility to prioritize the implementation of the various resiliency or security enhancements and modifications in their security plan according to risk, resources, or other factors. The requirement to include a timeline in the physical security plan for executing the actual physical security enhancements and modifications does not also require that the enhancements and modifications be completed within 120 days. The actual timeline may extend beyond the 120 days, depending on the amount of work to be completed.~~

~~Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).~~

~~A registered entity's physical security plan should include processes and responsibilities for obtaining and handling alerts, intelligence, and threat warnings from various sources. Some of these sources could include the ERO, ES-ISAC, and US and/or Canadian federal agencies. This information should be used to reevaluate or consider changes in the security plan and corresponding security measures of the security plan found in R5.~~

~~Incremental changes made to the physical security plan prior to the next required third party review do not require additional third party reviews.~~

~~Requirement R6~~

~~This requirement specifies review by an entity other than the Transmission Owner or Transmission Operator with appropriate expertise for the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5. As with Requirement R2, the term unaffiliated means that the selected third party reviewer cannot be a corporate affiliate (*i.e.,* the third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Operator). A third party reviewer also cannot be a division of the Transmission Operator that operates as a functional unit.~~

~~As noted in the guidance for Requirement R2, the prohibition on registered entities using a corporate affiliate to conduct the review, however, does not prohibit a governmental entity from selecting as the third party reviewer another governmental entity within the same political subdivision. For instance, a city or municipality may use its local enforcement agency, so long as the local law enforcement agency satisfies the criteria in Requirement R6. The third party reviewer, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.~~

~~The Responsible Entity can select from several possible entities to perform the review:~~

~~*An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*~~

~~In selecting CPP and PSP for use in this standard, the SDT believed it was important that if a private entity such as a consulting or security firm was engaged to conduct the third party review, they must tangibly demonstrate competence to conduct the review. This includes electric industry physical security experience and either of the premier security industry certifications sponsored by ASIS International. The ASIS certification program was initiated in 1977, and those that hold the CPP certification are board certified in security management. Those that hold the PSP certification are board certified in physical security.~~

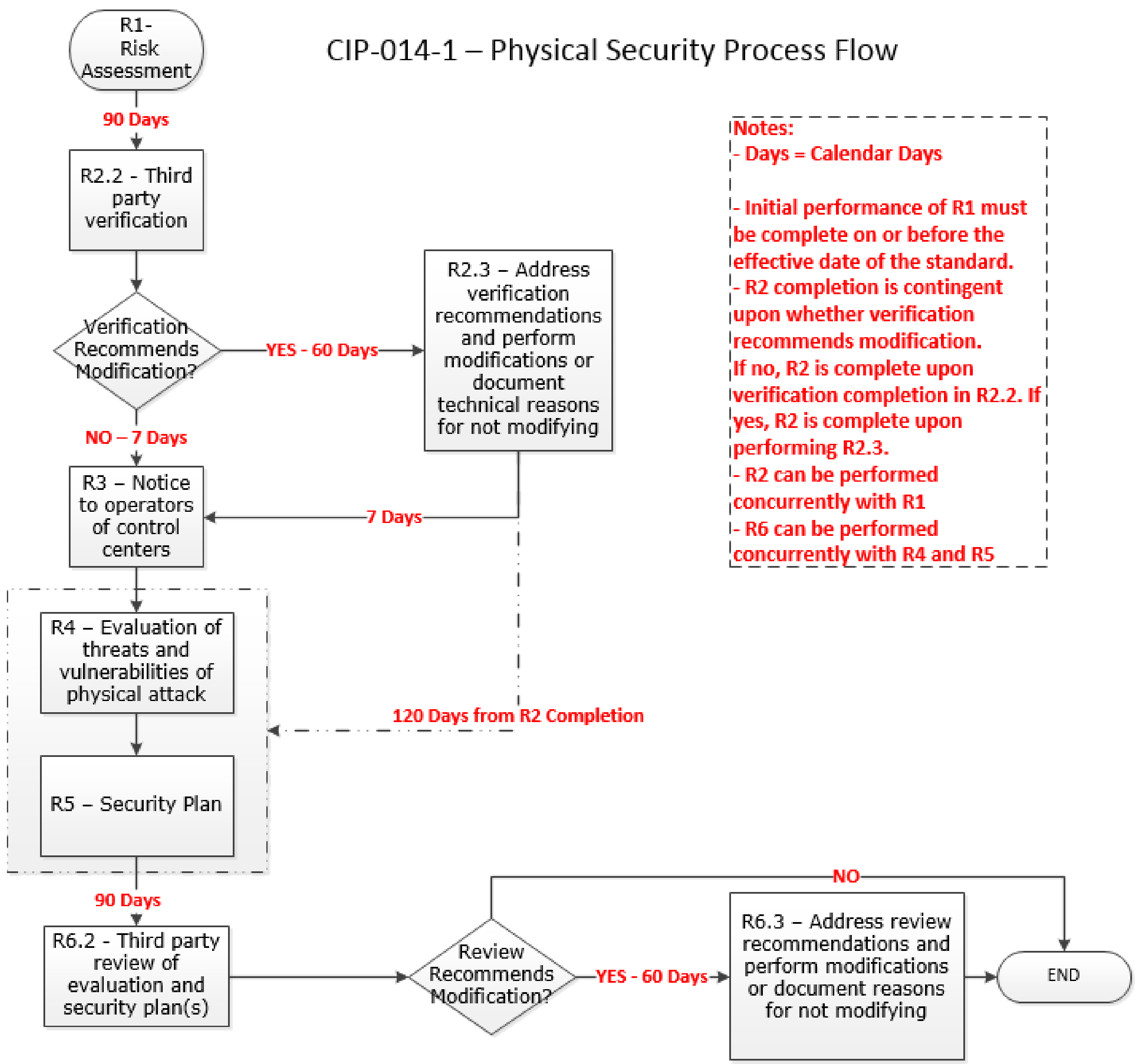
~~*An entity or organization approved by the ERO.*~~

~~*A governmental agency with physical security expertise.*~~

~~*An entity or organization with demonstrated law enforcement, government, or military physical security expertise.*~~

~~As with the verification under Requirement R2, Requirement R6 provides that the "review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5." This provision is designed to provide applicable Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout (*i.e.,* concurrent with) the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5, which for some Responsible Entities may be more efficient and effective. In other words, a Transmission Owner or Transmission Operator could collaborate with their unaffiliated third party reviewer to perform an evaluation of potential threats and vulnerabilities (Requirement R4) and develop a security plan (Requirement R5) to satisfy Requirements R4 through R6 simultaneously. The intent of Requirement R6 is to have an entity other than the owner or operator of the facility to be involved in the Requirement R4 evaluation and the development of the Requirement R5 security plans and have an opportunity to provide input on the evaluation and the security plan. Accordingly, Requirement R6 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the evaluation and develops the security plan itself and then has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the evaluation and develop the security plan.~~

~~Timeline~~


CIP-014-1 – Physical Security Process Flow
R1- Risk Assessment
90 Days
R2.2 - Third party verification
Verification Recommends Modification?
YES - 60 Days
R2.3 – Address verification recommendations and perform modifications or document technical reasons for not modifying
NO – 7 Days
R3 – Notice to operators of control centers
7 Days
R4 – Evaluation of threats and vulnerabilities of physical attack
120 Days from R2 Completion
R5 – Security Plan
90 Days
R6.2 - Third party review of evaluation and security plan(s)
Review Recommends Modification?
YES - 60 Days
R6.3 – Address review recommendations and perform modifications or document reasons for not modifying
NO
END
Notes:
- Days = Calendar Days
- Initial performance of R1 must be complete on or before the effective date of the standard.
- R2 completion is contingent upon whether verification recommends modification.
If no, R2 is complete upon verification completion in R2.2. If yes, R2 is complete upon performing R2.3.
- R2 can be performed concurrently with R1
- R6 can be performed concurrently with R4 and R5

~~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 Requirement R1:~~

~~This requirement meets the FERC directive from paragraph 6 of its March 7, 2014 order on physical security to perform a risk assessment to identify which facilities if rendered inoperable or damaged could impact an Interconnection through instability, uncontrolled separation, or cascading failures. The requirement is not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:~~

~~Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6~~

~~NERC EOP-004-2 reporting criteria~~

~~Area or magnitude of potential impact~~

~~Requirement R1 also meets the FERC directive for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection).~~

~~After identifying each Transmission station and Transmission substation that meets the criteria in Requirement R1, it is important to additionally identify the primary control center that operationally controls that Transmission station or Transmission substation (*i.e.,* the control center whose electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker, compared to a control center that only has the ability to monitor the Transmission station and Transmission substation and, therefore, must coordinate direct physical action through another entity).~~

~~Rationale for Requirement R2:~~

~~This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring verification by an entity other than the owner or operator of the risk assessment performed under Requirement R1.~~

~~This requirement provides the flexibility for a Transmission Owner to select registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term "unaffiliated" means that the selected verifying entity cannot be a corporate affiliate (*i.e.*, the verifying entity cannot be an entity that controls, is controlled by, or is under common control with, the Transmission owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit. The term "unaffiliated" is not intended to prohibit a governmental entity from using another government entity to be a verifier under Requirement R2.~~

~~Requirement R2 also provides the Transmission Owner the flexibility to work with the verifying entity throughout the Requirement R1 risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could coordinate with their unaffiliated verifying entity to perform a Requirement R1 risk assessment to satisfy both Requirement R1 and Requirement R2 concurrently.~~

~~Planning Coordinator is a functional entity listed in Part 2.1. The Planning Coordinator and Planning Authority are the same entity as shown in the NERC Glossary of Terms Used in NERC Reliability Standards.~~

~~Rationale for Requirement R3:~~

~~Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first identifying which Transmission stations and Transmission substations meet the criteria specified by Requirement R1, as verified according to Requirement R2. This requirement is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1, Part 1.2 of a Transmission station or Transmission substation verified according to Requirement R2 receives notice of such identification so that the Transmission Operator may timely fulfill its resulting obligations under Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include notice of the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or the verification process under Requirement R2.~~

~~Rationale for Requirement R4~~:

~~This requirement meets the FERC directive from paragraph 8 in the order on physical security that the reliability standard must require tailored evaluation of potential threats and vulnerabilities to facilities identified in Requirement R1 and verified according to Requirement R2. Threats and vulnerabilities may vary from facility to facility based on factors such as the facility's location, size, function, existing protections, and attractiveness of the target. As such, the requirement does not mandate a one-size-fits-all approach but requires entities to account for the unique characteristics of their facilities.~~

~~Requirement R4 does not explicitly state when the evaluation of threats and vulnerabilities must occur or be completed. However, Requirement R5 requires that the entity's security plan(s), which is dependent on the Requirement R4 evaluation, must be completed within 120 calendar days following completion of Requirement R2. Thus, an entity has the flexibility when to complete the Requirement R4 evaluation, provided that it is completed in time to comply with the requirement in Requirement R5 to develop a physical security plan 120 calendar days following completion of Requirement R2.~~

~~Rationale for Requirement R5:~~

~~This requirement meets the FERC directive from paragraph 9 in the order on physical security requiring the development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.~~

~~Rationale for Requirement R6:~~

~~This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring review by an entity other than the owner or operator with appropriate expertise of the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5.~~

~~As with the verification required by Requirement R2, Requirement R6 provides Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout the Requirement R4 evaluation and the development of the Requirement R5 security plan(s). This would allow entities to satisfy their obligations under Requirement R6 concurrent with the satisfaction of their obligations under Requirements R4 and R5.~~

Implementation Plan

Project 2023-06 CIP-014 Risk Assessment Refinement
Reliability Standard CIP-014-4

Applicable Standard(s)

- CIP-014-4 Physical Security

Requested Retirement(s)

- CIP-014-3 Physical Security

Applicable Entities

- Transmission Owner (TO)
- Transmission Operator (TOP)

General Considerations

The Drafting Team has determined that 24 calendar months for the CIP-014-4 implementation plan would allow adequate time for Transmission Owners and Transmission Operators to determine applicability, develop criteria, write or revise methodologies, perform assessments, and procure unaffiliated third parties for risk assessment verification (which some Transmission Owners have performed concurrently with their risk assessment analyses).

Effective Date of CIP-014-4

Where approval by an Applicable Governmental Authority is required, Reliability Standard CIP-014-4 shall become effective on the first day of the first calendar quarter 24 calendar months after the effective date of the Applicable Governmental Authority's order approving the standard or as otherwise provided for by the Applicable Governmental Authority.

Where approval by an Applicable Governmental Authority is not required, Reliability Standard CIP-014-4 shall become effective the first day of the first calendar quarter 24 calendar months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standard CIP-014-3 shall be retired immediately prior to the effective date of Reliability Standard CIP-014 in the particular jurisdiction in which the revised standard is becoming effective.

Project 2023-04 Modifications to CIP-003

Action
Inform

Background
Project 2023-04 Modifications to CIP-003 is currently revising CIP-003 to add controls to authenticate remote users, protect the authentication information in transit, and detect malicious communications assets containing low impact BES Cyber Systems with external routable connectivity. The first additional ballot was conducted from January 30 – March 14, 2024 and received 60.34 percent approval. The drafting team is continuing to make revisions based on industry comments with a plan to post an additional ballot in late May.

In April 2024 Project 2016-02 Modifications to CIP Standards completed its work on adding the option for virtualization to the CIP standards, which resulted in proposed Reliability Standard CIP-003-10. The NERC Board of Trustees will be asked to adopt this standard at its May 9, 2024 meeting.

Project 2023-04 will include in the second additional ballot two versions of the revised CIP-003 standard: (1) a revised CIP-003-11, with the low impact changes made against the last FERC-approved standard CIP-003-9; and (2) a draft CIP-003-12 standard, which include the low impact changes layered on top of the virtualization changes in CIP-003-10 from Project 2016-02. Including both versions in the second additional ballot will allow industry to see how both changes work together to provide a greater understanding of how implementing a new CIP-003 might work.

NERC Legal and Regulatory Update
March 9, 2024 – May 1, 2024

NERC FILINGS TO FERC SUBMITTED SINCE LAST SC UPDATE

FERC Docket No.	Filing Description	FERC Submittal Date
RD20-2-000	CIP SDT Schedule March Update Informational Filing NERC submitted an informational filing as directed by FERC in its February 20, 2020 Order. This filing contains a status update on one standard development project relating to the CIP Reliability Standards.	3/13/2024
RR24-2-000	Proposed Registry Criteria ROP Revisions (IBRs) NERC filed a request for Approval of Proposed Revisions to the Rules of Procedure (ROP) to Address Unregistered Inverter Based Resources (IBRs) and Request for Expedited Review under RD22-4-000.	3/19/2024
RM18-2-000	NERC Annual Report on Cyber Security Incidents NERC submitted the Annual Report on Cyber Security Incidents as directed by FERC in its July 19, 2018 Order.	3/21/2024
RR09-6-003	2024 NERC Standards Report, Status and Timetable for Addressing Regulatory Directives NERC submitted its 2024 NERC Standards Report, Status and Timetable for Addressing Regulatory Directives. The annual report is in accordance with Section 321.6 of the NERC Rules of Procedure.	3/22/2024
RD24-5-000	NERC Motion for Leave to Answer and Answer to Protest of ISO/RTO Council Regarding Proposed Reliability Standard EOP-012-2 Petition NERC submitted its answer to the Protest of the ISO/RTO Council regarding NERC's February 16, 2024 petition for approval of proposed Reliability Standard EOP-012-2.	4/4/2024

RR24-2-000	Answer to Comments on Proposed IBR ROP Revisions NERC submitted a Motion for Leave to Answer and Answer to comments on NERC's proposed revisions to its Rules of Procedure (ROP) to register unregistered inverter based resources (IBRs).	4/30/2024

FERC ISSUANCES SINCE LAST SC UPDATE

FERC Docket No.	Issuance Description	FERC Issuance Date
RD24-6-000	Order Approving Reporting ACE and Related Definitions FERC issued a letter order approving NERC's petition seeking approval of the proposed new and revised definitions of terms used in Reliability Standards related to Reporting ACE.	4/29/2024

ANTICIPATED UPCOMING FILINGS

FERC Docket No.	Filing Description	Anticipated Filing Date
TBD	Petition for Approval of WECC Regional Reliability Standard FAC-501-WECC-4	5/2024
TBD	Petition for Approval of Internal Network Security Monitoring Reliability Standard CIP-015-1	6/2024
TBD	Petition for Approval of CIP Virtualization Reliability Standards	TBD

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.