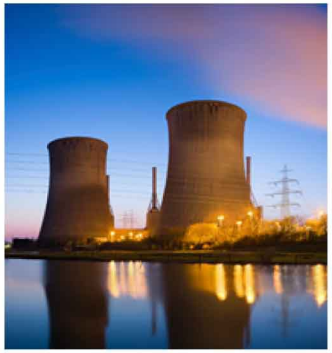
NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Industry Webinar

NERC Project 2023-06: CIP-014 Risk Assessment Refinement

July 8, 2025

RELIABILITY | ACCOUNTABILITY



Agenda

- Presenters
  - Drafting Team
    - Chair, Karl Perman, CIP Corps.
    - Drafting Team Member, David Schooley, Exelon
    - Drafting Team Member, Per-Anders Lof, National Grid
    - Drafting Team Member, Mina Turner, American Electric Power
  - NERC Staff
    - Ben Wu (Project Developer)
- Administrative Items
- Project Status and Background
- Additional Ballot Comments
- Draft 3 Revisions of CIP-014-4 and Associated Documents
- Next Steps
- Questions and Answers

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  - Information used herein is used for presentation purposes and may not reflect the actual work of the official posted materials.
- For the official record
  - This presentation is not a part of the official project record.
  - Comments must be submitted during the formal posting.
- Q&A Session
  - Q/A feature or chat feature.

Drafting Team (DT)

Name	Organization/ Company
Karl Perman (Chair)	CIP Corps
Patrick Quinn (Vice Chair)	Great River Energy
Per-Anders Lof	National Grid
Qamar Arsalan	Public Service Electric & Gas
David Schooley	Exelon
Joel Rogers	SERC Reliability Corporation
Kirpal Bahra	Hydro One Networks Inc.
Bart White	Duke Energy
Mina Turner	American Electric Power

Project Status

- The first additional posting was posted from September 23, 2024 through November 6, 2024.
- The drafting team received a lot of comments from the industry.
- The drafting team met 10 times from November 2024 through March 2025, including two in person meetings, to revise the Standard and associated documents based on the comments.
- The current posting started from June 6, 2025 and will end on July 21, 2025.

- 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.
- Purpose/Goal
  - 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.

Additional Ballot Comments

- Major Themes From Second Ballot Comments:
  - Planned to be in service
  - Near-term/Long-term Planning Horizon
  - Line of sight
  - Ease of access
  - Proximate
  - Steady-state and dynamic simulations
  - Fault conditions
  - Joint ownership/coordination
  - Flowchart
  - Implementation

Applicability Section Updates

- Applicability section
  - A reliability gap has been identified for the jointly owned Transmission stations or Transmission substations

4. Applicability:

4.1. Functional Entities:

4.1.1. Transmission Owner that owns or jointly owns one or more Transmission ~~station(s)~~stations or Transmission ~~substation(s)~~substations that meet the applicability criteria of Attachment 1.

Requirement R1 Updates and Proposed Language

Updates

- R1 (document applicable facilities)

Proposed Language

R1. Each Transmission Owner, at least once every 36 calendar months, shall ~~document a list of~~identify each applicable Transmission station~~(s)~~ and Transmission substation~~(s)~~ meeting any of the criteria in Attachment 1 that ~~are~~is either existing or planned to be in service within 36 calendar months. *[Violation Risk Factor: High; Time-Horizon: Long-term Planning]*

Requirement R2 Updates and Proposed Language

Updates

- R2 (documented proximity criteria)

Proposed Language

R2. Each Transmission Owner shall ~~have documented criteria to determine those~~identify proximate Transmission station(s) and Transmission substation(s), irrespective of ownership, within ~~½ mile~~1500 feet or 457 meters (the shortest distance, measured substation fence line to substation fence line) of an applicable Transmission station or Transmission substation ~~documented~~identified in Requirement R1~~, that could be impacted by a single physical attack. The criteria shall address at a minimum the following:~~. *[Violation Risk Factor: Medium; Time-Horizon: Long-term Planning]*

~~**2.1.** Line of sight between multiple Transmission station(s) or Transmission substation(s) from a single location without obstruction.~~

~~**2.2.** Ease of access from a common roadway that exists between multiple Transmission station(s) or Transmission substation(s).~~

Requirement R3 Updates and Proposed Language

Updates

- R3 (risk assessment methodology)

Proposed Language

R3. Each Transmission Owner shall have a documented risk assessment methodology~~, including criteria for steady-state and dynamic simulations,~~ for evaluating the loss ~~due to a physical attack~~ of each applicable Transmission station~~(s) and~~ or Transmission substation~~(s) documented~~ identified in Requirement R1~~ and Transmission substation(s) or Transmission station(s) determined to be in proximity per Requirement R2~~. The methodology shall include, at a minimum, the following: *[Violation Risk Factor: High; Time-Horizon: Long-term Planning]*

Requirement R3 Updates and Proposed Language Cont…

3.1. Documented criteria for assessing instability, uncontrolled separation, or Cascading within an Interconnection. The criteria shall include, at a minimum, thresholds identifying unacceptable generation and load loss within an Interconnection.

~~**3.1.** Technically supported thresholds and rationale for determining the amount of acceptable load loss, the amount of acceptable generation loss, post event response, and any additional considerations recognized as resulting in instability, uncontrolled separation, or Cascading within an Interconnection. The technical rationale shall include:~~

~~**3.1.1.** Steady state and dynamic system response to events that could lead to load loss, generation loss, and other unacceptable post event response within an Interconnection.~~

Requirement R3 Updates and Proposed Language Cont…

3.2. ~~Steady state~~A provision that steady-state and dynamic simulations shall each be performed ~~under System conditions that are more likely to contribute to instability, uncontrolled separation, or Cascading within an Interconnection~~using a System peak Load case and a System Off-Peak Load case.

3.3. A specification for Fault simulations, including:

~~**3.2.1.** The simulations shall include the removal of all Elements that Protection Systems and other controls are expected to automatically disconnect for each event.~~

~~**3.2.2.** If steady state and dynamic simulations each show acceptable system response but additional Elements trip during the dynamic simulation of an event, then additional steady state analysis including any tripped Elements from the dynamic simulations shall be conducted.~~

3.3.1. ~~**3.3.**~~ For each applicable Transmission station or Transmission substation listed in accordance with Requirement R1, ~~analysis shall include~~ a Fault at the applicable Transmission station or Transmission substation ~~and~~ .

- For each Transmission station or Transmission substation ~~identified~~determined in accordance with Requirement R2 as being in proximity to ~~the~~an applicable Transmission station or Transmission substation, Faults at both the applicable and proximate Transmission station(s) or Transmission substation(s).

Requirement R3 Updates and Proposed Language Cont…

3.4. A specification that Fault simulations ~~that~~ assume the loss of communication and Protection ~~System~~Systems at the applicable Transmission station(s) or Transmission substation(s) prior to or simultaneous with the Fault(s) studied under Requirement R3, Parts ~~3.2~~3.3.1 and ~~3.3~~3.3.2.

3.4.1. Removal of all Elements that Protection Systems and other controls are expected to automatically disconnect for each event.

3.4.2. ~~**3.4.1.**~~ Delayed (remote) clearing times shall be used unless otherwise technically substantiated.

3.4.3. ~~**3.4.2.**~~ Actual or more conservative ~~estimates of~~ clearing times shall be used unless otherwise technically substantiated.

Requirement R4 Updates and Proposed Language

Updates

- R4 (joint ownership/coordination)

Proposed Language

R4. Each Transmission Owner with applicable Transmission station(s) and Transmission substation(s) ~~per~~identified in Requirement R1 containing Bulk Electric System (BES) Elements owned by multiple Transmission Owners shall coordinate with ~~those~~each appropriate Transmission ~~Owners~~Owner(s) to determine and document their individual and joint responsibilities for documenting a risk assessment methodology under Requirement R3 and for performing any required risk assessments per Requirement R5. *[~~VRF~~Violation Risk Factor: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

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Requirement R5 Updates and Proposed Language

Updates

- R5 (risk assessment)

Proposed Language

R5. At least once every 36 calendar months, each Transmission Owner shall perform a risk assessment to identify applicable Transmission station(s) and Transmission substation(s) identified in Requirement R1, that if rendered inoperable or damaged ~~as a result of a physical attack~~ could result in instability, uncontrolled separation, or Cascading within an Interconnection, using the methodology established in Requirement R3, including any Transmission station(s) and Transmission substation(s) identified in accordance with ~~documentation established per~~ Requirement R4. If proximate Transmission station(s) and Transmission substation(s) were identified in Requirement R2, they should also be included in the risk assessment. *[~~VRF~~Violation Risk Factor: High; Time-Horizon: Operations Planning, Long-term Planning]*

Requirement R5 Updates and Proposed Language Cont …

5.1. ~~A~~During the current risk assessment, a Transmission station or Transmission substation identified in either the dynamic or steady-state ~~simulations~~simulation as causing instability, uncontrolled separation, or Cascading within an Interconnection when rendered inoperable or damaged ~~as a result of a physical attack does not require any additional simulations during the current risk assessment~~requires no further simulation.

5.2. If a previous risk assessment has identified a Transmission station or Transmission substation as causing instability, uncontrolled separation, or Cascading within an Interconnection when rendered inoperable or damaged, then the Transmission Owner may forgo additional assessments on that Transmission station or Transmission substation. Requirement R5, Part 5.3 and Requirement R7 through Requirement R10 still apply to that Transmission station or Transmission substation until a new risk assessment demonstrates otherwise.

5.3. ~~5.2.~~ The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified as causing instability, uncontrolled separation, or Cascading within an Interconnection when rendered inoperable or damaged in the Requirement R5 risk assessment.

Requirement Updates Since First Ballot Cont…

- R6 - R10 (out-of-scope requirements)
  - No material changes from last ballot

Attachment 1 – Applicability Criteria

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.

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~~N/A

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.

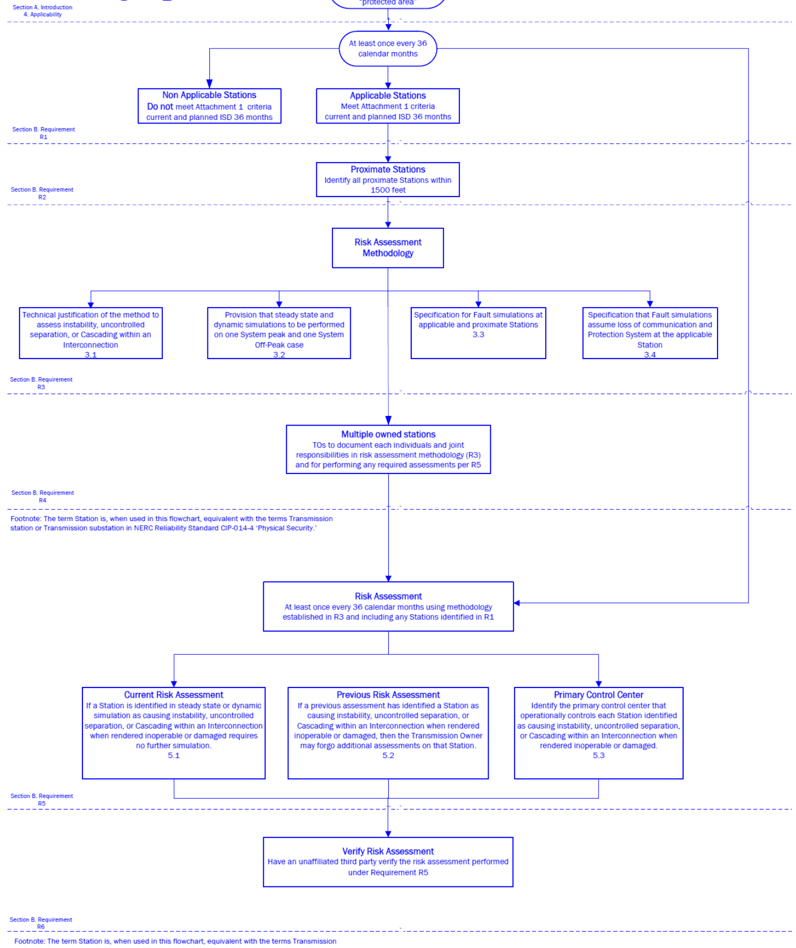
4. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements (NPIRs).

Technical Rationale

- Technical Rationale
  - Updated to reflect requirement changes
  - Added a Flowchart

CIP-014-4 Flowchart

(Added graphics)



- Implementation Plan Changes

Effective Date of CIP-014-4

~~The initial risk assessment required by CIP-014-4, Requirement R5, must be completed on or before the effective date of the standard.~~ 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 that is 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 on the first day of the first calendar quarter that is 24 calendar months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Initial Performance of Periodic Requirements

The initial risk assessment required by Reliability Standard CIP-014-4 Requirement R5, must be completed on or before the effective date of the standard. Subsequent risk assessments shall be performed no later than 36 calendar months following the effective date of Reliability Standard CIP-014-4.

Next Steps

- Posting
  - Project Page 2023-06
  - 45-day comment period and formal ballot June 6 – July 21, 2025
- Point of contact
  - Ben Wu, Senior Standards Developer
  - Ben.Wu@nerc.net or call 470-542-6882
- Webinar posting
  - Three business days
  - Standards Bulletin

Questions and Answers