NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project Update With PJM

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

October 17, 2025

RELIABILITY | ACCOUNTABILITY




Agenda

- Presenter
  - Karl Perman (Chair), CIP Corps.
- Administrative Items
- Project Status and Background
- Additional Ballot Comments
- Draft 4 Revisions of CIP-014-4 and Associated Documents
- Next Steps
- Questions and Answers

Drafting Team (DT)

Name	Organization/ Company
Karl Perman (Chair)	CIP Corps
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Per-Anders Lof	National Grid
Qamar Arsalan	Public Service Electric & Gas
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Kirpal Bahra	Hydro One Networks Inc.
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Project Status

- The first additional posting was posted from September 23, 2024 through November 6, 2024.
- The second additional posting was posted from June 6 – July 21, 2025.
- The drafting team received a lot of comments from the industry.
- The drafting team met 11 times from August 2025 through September 2025 to revise the Standard and associated documents based on the comments.
- The current posting is planned in October, 2025.

Background

- 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:
  - 36 calendar months vs. 60 calendar months
  - BES for proximate stations
  - Thresholds for unacceptable generation and load loss
  - Loss of communication for proximate stations
  - Fault conditions
  - Implementation

Purpose Statement

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 due to a physical attack, could ~~cause~~ result in instability, uncontrolled separation, or Cascading within an Interconnection.

Requirement R1 Updates and Proposed Language

Updates

- R1 (document applicable facilities) – No change

Requirement R2 Updates and Proposed Language

Updates

- R2 (documented proximity criteria)

Proposed Language

R2. Each Transmission Owner with applicable Transmission station(s) or Transmission substation(s) identified in Requirement R1 shall identify proximate existing Bulk Electric System (BES) Transmission station(s) and BES Transmission substation(s), irrespective of ownership, within 1500 feet or 457 meters (the shortest distance, measured substation fence line to substation fence line) of an applicable Transmission station or Transmission substation identified in Requirement R1. *[Violation Risk Factor: Medium; Time-Horizon: Long-term Planning]*

Requirement R3 Updates and Proposed Language

Updates

- R3 (risk assessment methodology)

Proposed Language

R3. Each Transmission Owner shall have a documented risk assessment methodology for evaluating the loss of each applicable Transmission station or Transmission substation identified in Requirement R1. The methodology shall include, at a minimum, the following: *[Violation Risk Factor: High; Time-Horizon: Long-term Planning]*

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

3.2. A provision that steady-state and dynamic simulations shall each be performed using at least a System peak Load case and a System Off-Peak Load case.

Requirement R3 Updates and Proposed Language Cont…

3.3. A specification for Fault simulations at each applicable Transmission station or Transmission substation listed in accordance with Requirement R1 that~~,~~ includ~~ing~~:

- **3.3.1.** Prior loss of communication and Protection Systems ~~For each applicable Transmission station or Transmission substation listed in accordance with Requirement R1, a Fault~~ at the applicable Transmission station or Transmission substation; and~~.~~

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

3.3.3. Removal of all Elements that Protection Systems and other controls are expected to automatically disconnect; and

3.3.4. Use of delayed (remote) clearing times unless otherwise technically substantiated.

- **3.3.4.1.** Use of actual or more conservative clearing times unless otherwise technical substantiated.

Requirement R3 Updates and Proposed Language Cont…

3.4. A specification ~~that~~ for Fault simulations at each proximate BES Transmission station or BES Transmission substation determined in accordance with Requirement R2 that include: ~~assume the loss of communication and Protection Systems at the applicable Transmission station(s) or Transmission substation(s) prior to or simultaneous with the Fault(s) studied under Requirement R3, Parts 3.3.1 and 3.3.2.~~

- **3.4.1.** ~~Removal of all Elements that Protection Systems and other controls are expected to automatically disconnect for each event~~A Fault at each proximate BES Transmission station or BES Transmission substation either simultaneous or following the Fault at the applicable Transmission station or Transmission substation;~~.~~

- **3.4.2.** ~~Delayed (remote) clearing times shall be used unless otherwise technically substantiated.~~ Removal or all Elements that Protection Systems and other controls are expected to automatically disconnect; and

3.4.2.1. ~~Actual or more conservative clearing times shall be used~~Use normal clearing times 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) identified in Requirement R1 jointly ~~containing Bulk Electric System (BES) Elements~~ owned by multiple Transmission Owners shall coordinate with each appropriate Transmission Owner(s) to determine and document their individual and joint responsibilities for performing ~~documenting a risk assessment methodology under~~ Requirement R3 and ~~for performing any required risk assessments per~~ Requirement R5. *[Violation Risk Factor: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

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 could result in instability, uncontrolled separation, or Cascading within an Interconnection, using the methodology established in Requirement R3, ~~including~~ recognizing any Transmission station(s) and Transmission substation(s) ~~identified~~ in accordance with Requirement R4. If proximate BES Transmission station(s) and BES Transmission substation(s) were identified in Requirement R2, they ~~should~~ shall also be included in the risk assessment per Requirement R3, Part 3.4. *[Violation Risk Factor: High; Time-Horizon: Operations Planning, Long-term Planning]*

Requirement R5 Updates and Proposed Language Cont …

5.1. If ~~D~~during ~~the current~~ a risk assessment, a Transmission station or Transmission substation is identified in either the dynamic or steady-state simulation as causing instability, uncontrolled separation, or Cascading within an Interconnection when rendered inoperable or damaged, ~~requires~~ then no further simulation is required.

Requirement Updates Since First Ballot Cont…

Updates

- R7 (primary control center(s))

R7. For a primary control center(s) identified by the Transmission Owner according to Requirement R5, Part 5.3~~2~~ that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R6, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R6, notify the Transmission Operator that has operational control of the primary control center of such identification and the date of completion of Requirement R6. *[Violation Risk Factor: Lower; 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.

Requirement Updates Since First Ballot Cont…

- R6, R8 - R10 (out-of-scope requirements)
  - No material changes from last ballot

Technical Rationale

- Technical Rationale
  - Updated to reflect requirement changes

Implementation Plan

- Implementation Plan Changes

Applicable Entities

- ~~Transmission Owner (TO)~~Transmission Owner that owns or jointly owns one or more Transmission stations or Transmission substations that meet the applicability criteria of Attachment 1
- Transmission Operator ~~(TOP)~~

  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 (NRC) 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.

Implementation Plan Cont…

General Considerations

In developing this Implementation Plan, ~~T~~the Drafting Team (DT) 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).

In determining an appropriate timeframe, the DT considered the severity of the concerns highlighted in the FERC's December 2022 order that which directed NERC to evaluate the effectiveness of CIP-014-3 in mitigating the risks to the BPS associated with physical attacks. (*N. Am. Elec. Reliability Corp.*, 181 FERC ¶ 61,230 (2022) (December 2022 Order); (2) the recommendations of the NERC report entitled *Evaluation of the Physical Security Reliability Standard and Physical Security Attacks to the Bulk-Power System* (*See* NERC Report on CIP-014-3.pdf, filed with FERC on April 14, 2023); and (3) the SAR requirement that the DT correct any discrepancies between the study period, frequency of study, and the base case(s) a Transmission Owner uses. The DT determined that an Implementation Plan schedule of 24 calendar months appropriately balances the reliability need and risks against the time and resources required of entities to determine applicability, develop criteria, write or revise methodologies, perform assessments, and procure unaffiliated third parties for risk assessment verification.

Next Steps

- Posting
  - Project Page 2023-06
  - 45-day comment period and formal ballot in November, 2025
- Point of contact
  - Ben Wu, Senior Standards Developer
  - Ben.Wu@nerc.net or call 470-542-6882

Questions and Answers