Technical Rationale

Project 2023-06 CIP-014 Risk Assessment Refinement
Reliability Standard CIP-014-4 | May 2024

CIP-014-4 – Physical Security

Rationale for Requirement R1
Performing Risk Assessments
Requirement R1 is developed to ensure that each Transmission Owner establishes a list of applicable Transmission station(s) or Transmission substation(s) in accordance with Attachment 1 that aligns with the periodicity of the risk assessment outlined in Requirement R4. Aligning the 36 months look ahead in Requirement R1 Part 1.1 with the 36 month cycle for conducting risk assessment in accordance with Requirement R4 ensures that system topology of the cases used to assess applicability is consistent with the system topology in the Requirement R4 risk assessment models. . Making the applicability section a separate requirement allows Transmission Owners the option to bypass the remaining requirements in the standard if they do not have any applicable Transmission station(s) or Transmission substation(s).

Rationale for Requirement R1 1.1
In performing the risk assessment, the Transmission Owner should first identify their population of Transmission stations and Transmission substations that meet the criteria contained in Attachment 1. The Standard 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 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 identify candidates for such Transmission station(s) and Transmission substation(s), the Transmission Owner shall evaluate the criteria listed in Attachment 1.

Rationale for Requirement R1 1.2
Transmission Owners shall review and, if necessary, update the list of applicable Transmission station(s) or Transmission substation(s) per Attachment 1 every 36 months. The list of applicable Transmission station(s) or Transmission substation(s) shall include existing or planned to be in service within 36 months Transmission station(s) and Transmission substation(s). The 36-month cycle for updating the list of applicable Transmission station(s) or Transmission substation(s) per Attachment 1 aligns with the annual cycle for performing Planning Assessments per NERC Standard TPL-001. The 36-month risk assessment study cycle aligns with the 36-month planned-to-be-in-service date.

Rationale for Requirement R1 1.3

Requirements R2 through R4 define requirements that are only relevant when a TO has applicable Transmission substations or Transmission stations. The remaining requirements are therefore, unnecessary if the TO does not have any applicable Transmission substations or Transmission substations.

Rationale for Requirement R2

Each Transmission Owner shall consider, at a minimum, the specifications in Requirement R2, parts 2.1.1, 2.1.2, and 2.1.3 for general applicability to their systems, and whether specifications and thresholds need to be stipulated for each of these parts in their documented criteria.

A certain amount of discretion and flexibility is intended to be allowable for each Transmission Owner in their respective proximity Criteria to document, establish, and demonstrate from a technical basis that various aspects of proximity for their Transmission station(s) or Transmission substation(s) either are or are not appropriate to consider in their risk assessments.

The DT has determined that protecting the applicable Transmission station(s) or Transmission substation(s) in a proximity group will render a physical attack on that proximity group to be ineffective. The DT has also determined that if the applicable Transmission station(s) or Transmission substation(s) in consideration is added to the Transmission Owner's critical list for physical protection, the risk analysis for that Transmission station or Transmission substation, including any analysis that would be performed based on Requirement R2, can be foregone and considered to be complete.

The DT has determined that if a proximity group has been identified, that analysis of the proximity groups should be required in each Transmission Owner's documented criteria. This includes proximity groups comprising of Transmission station(s) or Transmission substation(s) that are owned by two or more entities. For those scenarios, it is the responsibility of any and all applicable Transmission Owners to ensure that this determination is properly addressed, and appropriate action taken pursuant to analysis.

Rationale for Requirement R3

Per requirement R3, each Transmission Owner is required to have a risk assessment methodology, but the SDT intends for each TO to have flexibility to define its own methodology, including the criteria by which analytical results will be examined to determine if a Transmission station or Transmission substation can be considered critical for the interconnection. The TO is not required to develop its own methodology and is free to use a methodology developed elsewhere, such as in coordination with neighboring TOs or ISOs.

Rational for Requirement R3, Part 3.1

TOs should have the flexibility to determine the amount of acceptable load loss, acceptable generation loss, or other measurements of system response when determining the impact of an event to the transmission system. Criteria for measures such as load loss or generation loss should consider the impact to the interconnection instead of local impacts. For that reason, the loss of load over multiple Transmission stations or Transmission substations should have a higher criticality than losing the same amount of load at a single Transmission substation or Transmission substation.

Large loss of generation or large load due to the evaluated disturbance, as well as consequences of isolating faulted equipment, could result in severe System impacts. The documented risk assessment methodology shall include 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. Conditions and thresholds for these used for determining critical Transmission station(s) or Transmission substation(s), i.e., those that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection, should be part of the documented risk assessment methodology.

Rationale for Requirement R3, Part 3.1.1

The items listed in Parts 3.1.1.1 through 3.1.1.2 are all post-event measures that can be used to assess the criticality of a Transmission substation or Transmission substation. While all of these items shall be considered, a TO can decide that one or more of the items are not applicable to their location within the interconnection.

Transmission Owners shall develop documented criteria for the conditions listed in Requirement R3, Part 3.1.1, which includes branch thermal exceedance thresholds, bus voltage exceedance thresholds, load loss thresholds, generation loss thresholds, etc.

Rationale for Requirement R3, Part 3.2

Dynamic simulations are required by the SAR after NERC and FERC determined that steady-state simulations alone are insufficient for determining whether or not a substation is critical. Analyses must be performed at system conditions that demonstrate criticality. Part 3.2.1 states that dynamic simulations are not required when a TO has determined that a Transmission station or Transmission substation is critical via steady-state analysis. Dynamic can still be performed if desired by the TO.

Transmission Owners shall develop documented criteria for the conditions listed in Requirement R3, Part 3.1.1, which includes branch thermal exceedance thresholds, bus voltage exceedance thresholds, load loss thresholds, generation loss thresholds, etc.

Rationale for Requirement R3, Part 3.3

Steady-state simulations can account for criteria such as relay loadability and cascading line tripping in ways that are difficult for dynamic simulations. For that reason, steady-state simulations must be performed for any Transmission stations or Transmission substations that were not determined to be critical in the dynamic simulations. Analyses must be performed at system conditions that demonstrate criticality. Part 3.3.1 states that dynamic simulations are not required when a TO has determined that a Transmission station or Transmission substation is critical via steady-state analysis. Dynamic can still be performed if desired by the TO.

Since physical attaches can take place during different times and seasons, Requirement R3, Part 3.3, requires the Transmission Owner to perform risk assessments based on steady state studies for System peak, Off-Peak Load, and other System conditions.

Rationale for Requirement R3, Part 3.4
The DT believes that a three-phase fault at the highest voltage bus is a reasonable assumption for possible events that could impact a single Transmission station or Transmission substations.

Rationale for Requirement R3, Part 3.5
The DT believes that simultaneous single-phase faults are a reasonable assumption for events that could simultaneously impact multiple Transmission stations or Transmission substations.

Rationale for Requirement R3, Part 3.6
The requirement that simulations shall assume the loss of communications and system protection is consistent with the SAR. It is also consistent with the use of "inoperable" in the standard.

Rationale for Requirement R3, Part 3.6.1
The DT believes that the use of delayed or remote clearing times is consistent with the description of a Transmission station or Transmission substation being rendered inoperable by an event that disabled local protection systems.

Rationale for Requirement R3, Part 3.6.2
While there are commonly used generic clearing times for remote clearing that are consistent across the industry, actual clearing times can be shorter or longer depending on conditions and design considerations at an individual TO. The difference of a few cycles can have a significant impact on the transient behavior of generating units, therefore, it is required that the risk analysis use clearing times that are as accurate as possible.

Rationale for Requirement R4
The SAR directed the DT to address joint ownership as part of the risk assessment. The periodicity of the coordination and risk assessment were aligned.

Rationale for Requirement R5
An objective of the CIP-014-3 Risk Assessment Refinement SAR was to align study periods, frequency of studies and the powerflow models used for the studies. A 36-month periodicity was chosen for the R4 risk assessment to reduce the periodicity options from previous versions of the standard. Additionally, a single study periodicity is more easily aligned with project in-service date considerations and model choices. As called for in Project Scope item 3 of the CIP-014-3 Risk Assessment Refinement SAR, the risk assessment must comply with the methodology developed in R3, so this language was explicitly added to R5.

Joint ownership of Transmission substations and Transmission stations was discussed in the Guidelines and Technical Basis of previous versions of the CIP-014 standard. Because the CIP-014-3 Risk Assessment Refinement SAR calls for clarification regarding Transmission substations and Transmission stations of differing ownership, this section was moved to its own requirement within R5.

Transmission Owners shall review and, if necessary, update the list of applicable Transmission station(s) or Transmission substation(s) per Attachment 1 every 36 months. The list of applicable Transmission station(s) or Transmission substation(s) shall include existing or planned to be in service within 36 months Transmission station(s) and Transmission substation(s). The 36-month cycle for updating the list of applicable Transmission station(s) or Transmission substation(s) per Attachment 1 aligns with the annual cycle for performing Planning Assessments per NERC Standard TPL-001. The 36-month risk assessment study cycle aligns with the 36-month planned-to-be-in-service date.

Rationale for Requirement R5, Part 5.2
<u>Identification of Primary Control Centers</u>
Previous R1.3
After completing the risk assessment under Requirement R4 and verified under Requirement R5, 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 R6 through Requirement R10 are Requirement R2 through Requirement R6 in CIP-014-3. The Drafting Team did not make any changes to these Requirements. Therefore, the technical rationales are not provided here.

Rationale for Attachment 1
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 primarily applies to Transmission Owners that own Transmission Facilities that meet the specific applicability criteria in Attachment 1. The Facilities described in Attachment 1 mirror those Transmission Facilities that meet bright line criteria for "Medium Impact" Transmission Facilities under Attachment 1 of Reliability Standard CIP-002-5.1a. Each Transmission Owner that owns Transmission Facilities that meet the criteria in Attachment 1 is required to perform a risk assessment 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.

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 R6 that the Transmission Operator operates a primary control center that operationally controls a Transmission station(s) or Transmission substation(s) identified in the Requirement R4 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 R7 through R9. 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 R4 and verified in Requirement R5. Control centers that provide back-up capability are not applicable, as they are a form of resiliency and intentionally redundant.

The DT determined that continuing to use criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1a would provide a conservative threshold for defining which Transmission stations and Transmission substations that must be included in the risk assessment in Requirement R4 of CIP-014. Additionally, the DT concluded that using CIP002-5.1a 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-002-5.1a, 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).

Additionally, the DT 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.

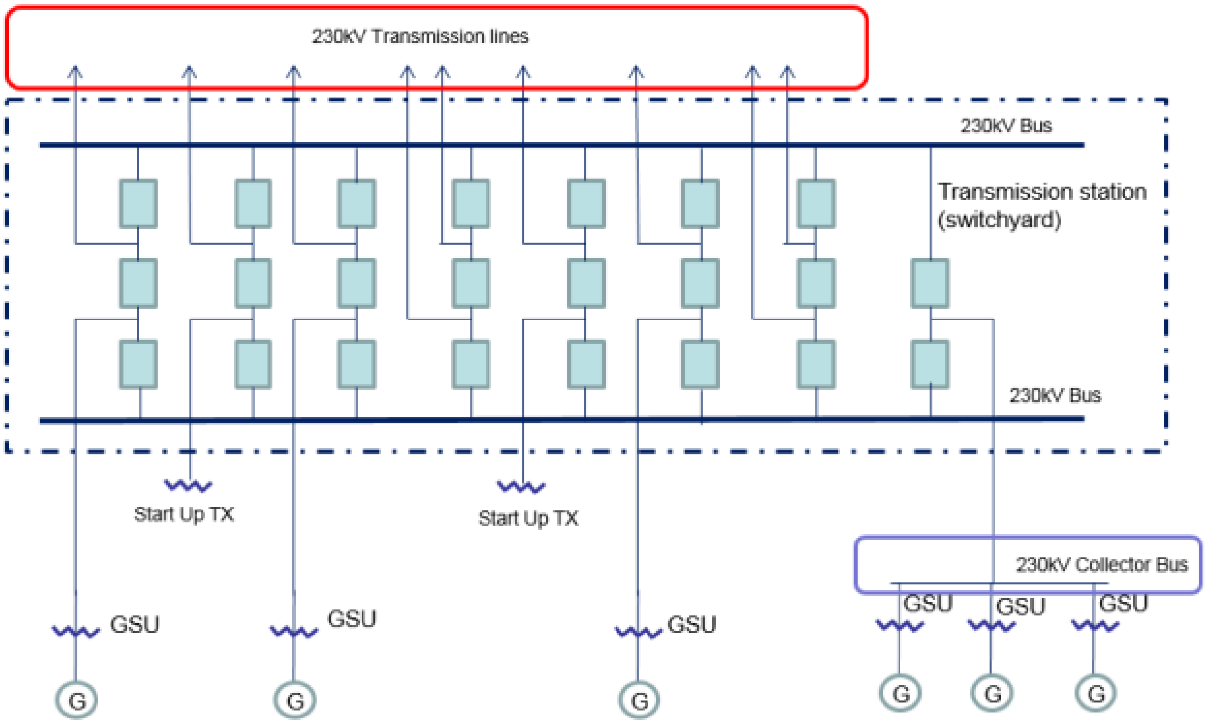

Figure from CIP-014-3 Guidelines and Technical Basis

Also, the DT uses the phrase "Transmission station(s) or Transmission substation(s)" 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 DT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.