

ERO Enterprise CMEP Practice Guide

Version 1.1

CIP-014-3 R1

September 19, 2022

Background

In support of successful implementation and compliance with the North American Electric Reliability Corporation (NERC) Reliability Standards, the Electric Reliability Organization (ERO) Enterprise¹ adopted the Compliance Guidance Policy.² The Compliance Guidance Policy outlines the purpose, development, use, and maintenance of guidance for implementing Reliability Standards. According to the Compliance Guidance Policy, Compliance Guidance includes two types of guidance: Implementation Guidance and Compliance Monitoring and Enforcement Program (CMEP) Practice Guides.³

Purpose

CMEP Practice Guides developed solely by the ERO Enterprise to reflect the independent, objective, professional judgment of ERO Enterprise CMEP staff (CMEP staff) and may be initiated at times following policy discussions with industry stakeholders. Following development, guides are posted for transparency on the NERC website.

It is noted, especially to registered entities using this guide as a reference that some parts of the guide are to assist CMEP staff in understanding how an entity mitigates risk to inform risk-based compliance monitoring, while other aspects of this guide may assist CMEP staff directly in determining compliance. This understanding of the controls to mitigate risk can affect monitoring activities, requests for information, and adjustments to an entity's compliance oversight plan.

The purpose of this CMEP Practice Guide is to provide guidance to CMEP staff during the review of an entity's risk assessments as prescribed in the Reliability Standard. The ERO Enterprise identified a need to recommend a common approach to auditing CIP-014-3: Physical Security.⁴ This need was identified through several CMEP engagements, including through CIP-014-3 audits, where NERC participated as team members, and a review of currently endorsed Implementation Guidance.⁵ An ERO Enterprise peer review of previous CIP-014-3 audits revealed that the technical rationale provided by entities frequently did not provide a sufficient technical supporting basis to demonstrate how the entity evaluated instability, uncontrolled separation, or Cascading. These audits have exposed a gap where additional technical

¹ The ERO Enterprise consists of NERC and the six Regional Entities.

² The [ERO Enterprise Compliance Guidance Policy](#)

³ Implementation Guidance provides a means for registered entities to develop examples or approaches to illustrate how registered entities could comply with a standard that are vetted by industry and endorsed by the ERO Enterprise. CMEP Practice Guides differ from Implementation Guidance in that they address how ERO Enterprise CMEP staff executes compliance monitoring and enforcement activities, rather than examples of how to implement the standard.

⁴ [NERC Reliability Standard: CIP-014-2](#)

⁵ [NERC Implementation Guidance](#)

rationale may be needed to ensure that transmission analyses in CIP-014-3 fulfill the purpose and requirement language of the Reliability Standard. While currently endorsed Implementation Guidance is effective in providing an example of one way an entity could be compliant with CIP-014-3, additional entity-specific facts and circumstances are to be considered by CMEP staff when assessing risks and determining compliance. Risk information can be used to inform CMEP staff's understanding of a registered entity (e.g., Compliance Oversight Plan, audit approach). Compliance determinations are to be made in consideration of specific facts and circumstances of the individual registered entities and the language of the Requirements.

Summary of Audit Approach

CMEP staff shall evaluate several key factors when reviewing evidence of effective risk assessments to identify Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection:

- **Applicability List:** Understanding how a registered entity develops and maintains an “applicability list” (a list of Transmission station(s) and Transmission substation(s) applicable to the criteria specified in CIP-014-3 Applicability Section 4.1.1) is critical to ensuring a complete risk assessment of transmission analyses. Unique aspects of Transmission facilities and configurations influence the aggregated weighting and resulting identifications of applicable stations/substations to study.
- **Models:** Understanding how an entity selected and prepared models(s) to perform the risk assessment is vital for validating the risk assessment with all applicable Transmission station(s) and Transmission substation(s), including those already existing and planned to be in service within 24 months of the risk assessment. The completeness, characteristics, and adequacy of the model(s) notably affect results of risk assessments.
- **Technical Analyses:** Ensuring risk assessments consist of transmission analysis or transmission analyses carefully 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. Entities' processes for performing risk assessments must adequately study the loss of those stations. Processes should include thorough technical criteria and supporting information for system Stability, uncontrolled separation, and Cascading analyses.

Detailed Recommended Approach to Audit R1

The language within CIP-014-3 does not prescribe a specific method on how each risk assessment of the entity's Transmission station(s) and Transmission substation(s) shall be performed. As such, specific components that comprise any supporting analytics are neither defined nor listed. This provides intentional flexibility for various approaches to the CIP-014-3 R1 risk assessment, due to the expected differences in each individual entity's facts and circumstances. However, that flexibility does not alter R1's language that each risk assessment *must* be “designed to identify” which applicable Transmission station(s) and Transmission substation(s), that if rendered inoperable or damaged, could result in instability, uncontrolled separation, or Cascading within an Interconnection. Entities may implement different approaches to complete this objective, but the approach must be able to accomplish the fundamental obligation of the

requirement through effectively assessing all required adverse system conditions with sufficient supporting technical analyses.

As such, CMEP staff shall consider entity-specific processes and study assumptions to evaluate if an entity has adhered to the full objective of the requirement language. This document discusses two specific types of analyses (i.e., steady state and dynamic) to evaluate different system characteristics and responses during similar conditions. CMEP staff should be familiar with the technical differences between these two types of analyses and their capability (and any limitations) to identify instability, uncontrolled separation, and Cascading. There may be other technical studies that evaluate these adverse system conditions that may be incorporated as part of the overall risk assessment. In any case, the registered entity should be able to demonstrate how the approach fulfills the requirement.

The following topics are considered when assessing the entity's approach to performing each risk assessment: **Applicability List**, **Models**, and **Technical Analyses**. For each topic, this document provides an overall expectation of CMEP staff.

Applicability List

The Transmission station(s) and Transmission substation(s) that apply under CIP-014-3 are based on aggregated values of lines that may have multiple electrical buses within the base cases but are physically contained in a location. This applicability list is created and maintained by the Transmission Owner and is essential to ensuring a complete study.

- **List Development and Maintenance:** The CIP-014-3 applicability list is not typically automated through current tools and practices. This due to aggregated weighting performed at the Transmission station(s) and Transmission substation(s) level rather than by buses or by a collection of buses of a single voltage class. Unique variations of certain Transmission Facilities add complexity to the aggregated weighting, such as split buses, ring buses, multiple ownership configurations, and other topology variations that may need a human evaluation to ensure that lines and connecting Transmission station(s) and Transmission substation(s) are correctly counted.
 - To understand the process and controls that an entity has implemented to ensure its applicability list accuracy, CMEP staff reviews shall include verifying identification of the following:
 - Transmission Facilities operated at 500 kV or higher (the collector bus for a generation plant may be excluded as noted in Applicability Criterion 4.1.1.1).
 - Transmission Facilities operating between 200 kV and 499 kV meeting the Applicability Criterion 4.1.1.2 (All transmission Facilities at a single Transmission station or Transmission substation identified by their Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operation Limits (IROLs) and their associated contingencies (Applicability Criterion 4.1.1.3)).
 - All transmission Facilities identified as essential to meeting nuclear plant interface requirements (Applicability Criterion 4.1.1.4).

- CMEP staff shall consider whether electrically disconnected buses (including electrically disconnected buses without interrupting switchgear or breakers) are counted as a single Transmission station or Transmission substation based on their physical proximity. An example of the type of factors to consider when assessing close proximity is where proximity is defined as having two or more substations situated such that one or more of the following apply:⁶
 - An easy line-of-sight between the entire substation yards from a single site.
 - An easy access from a common public roadway that exists between all of the substation yards.
 - The substation yards are in close enough proximity that a single event can impact both substations (e.g., the debris field from an incendiary device set off at one yard will impact the other yard).
- Normally open lines between radial systems are to be reviewed in accordance with the Bulk Electric System (BES) definition to determine if they meet the criteria specified in CIP-014-3 Applicability Section 4.1.1 or they may be excluded by the BES Exception process.
- As risk, assessments evaluate potential physical events or threat vectors that affect the Transmission station(s) or Transmission substation(s) rather than a fault that is typically studied by transmission planners, evaluations of Transmission station(s) and Transmission substation(s) should include all physically adjacent elements regardless of ownership. The physically adjacent elements should not be limited by a substation fence, interposing roads, streets, or highways. The risk assessment should consider all Transmission Facilities that could be subject to a common physical attack. CMEP staff may apply various methods to test the validity of the CIP-014-3 applicability list, including:
 - Reviewing system maps, which are often color-coded and may allow CMEP staff quickly identify larger Transmission Facility hubs.
 - Using the locations identified on the system maps, reference publicly available mapping tools to compare the number of lines to the CIP-014-3 applicability list and system maps. Maps show the larger picture, and individual station/substation one-lines may be obtained to look at an individual station detail if needed.
 - Considering performing field visits if other evidence provided by an entity indicates a potential deficient methodology for identifying physical adjacency.
- CMEP staff shall ascertain whether a jointly owned Transmission station or Transmission substation is clearly indicated to ensure that each Transmission station and Transmission substation is assessed by the responsible entity(ies).
 - CMEP staff may assess what internal controls are in place to ensure timely and accurate Facility information is used for identifying applicable Transmission station(s) and Transmission substation(s). For jointly owned Transmission station(s) and Transmission

⁶ [ERO Endorsed Implementation Guidance: NATF CIP 014-2 Requirement R1 Guideline](#)

- substation(s), documentation should be provided explaining which owner has compliance responsibility for the entire site.
- CMEP staff shall verify entities are including all Transmission lines at jointly owned as well as physically adjacent separately owned Transmission station(s) and Transmission substation(s) in the calculation of line weighting.
 - CMEP staff shall understand how the entity ensures all Transmission lines are correctly identified for each Transmission station and Transmission substation per the Standard.
 - Note that some entity one-line diagrams may not demonstrate equipment owned by other owners at jointly owned Transmission station(s) and Transmission substation(s) nor the overall physical boundaries of physically adjacent equipment.
 - CMEP staff shall consider recommending entities clearly indicate ownership of Transmission lines for jointly owned Transmission station(s) and Transmission substation(s).
 - CMEP staff shall consider using the system map and satellite imagery methods described earlier to ascertain if separately owned physically adjacent stations/substations were considered.
 - Under the ERO Enterprise CMEP Manual’s guidance on sampling, CMEP staff may consider sampling the list of all Transmission station(s) and Transmission substation(s) to evaluate for completeness and accuracy.⁷ This sample set can be compared against transmission planning one-line diagrams, operational diagrams, or other entity data that demonstrate the number of lines, voltage classes, and Transmission station(s) and Transmission substation(s) physical configurations.
 - To verify consistency with similar evaluations performed under CIP-002-5.1a,⁸ CMEP staff may review the CIP-014-3 applicability list and CIP-002 R1 identifications.
 - **Line Taps:** It is not uncommon for a Transmission line to be tapped outside the physical boundary of a Transmission station(s) and Transmission substation(s), resulting in a connection of one Transmission station(s) and Transmission substation(s) to two separate Transmission station(s) or Transmission substation(s). CMEP staff shall consider the following to ascertain whether lines that meet this condition are aggregated properly for the purpose of developing the applicability list:
 - If a line is tapped outside of the physical configuration of a Transmission station or Transmission substation and connects to two separate Transmission station(s) or Transmission substation(s):
 - This connection to two Transmission station(s) or Transmission substation(s) is counted to determine if the Transmission station or Transmission substation connects to “three or more other Transmission station(s) or Transmission substation(s).”
 - This single line is counted for to add a line weighting to the total value of that Transmission station or Transmission substation.

⁷ [ERO Enterprise Compliance Monitoring and Enforcement Manual](#)

⁸ [NERC Reliability Standard CIP-002-5.1a](#)

- A generator lead-in line tap is not counted towards the line weighting.

Models

R1 provides the following regarding the model(s) used to perform the risk assessment:

“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.”

CMEP staff shall understand how an entity selects and prepares models(s) to perform the risk assessment in R1. This includes the entity’s determination of the planned projects within 24 months included within the model, the selection of stress scenarios or conditions, and ensuring that the model is appropriate. Per Requirement R1, R1.1, 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 one or more Transmission station(s) or Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection if rendered inoperable or damaged.

The 30-month time frame 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. For example, a Transmission Owner may choose to conduct a risk assessment once every 24 months to align with its planning cycle and leverage this flexibility of the requirement. From the Guidelines and Technical Basis of CIP-014-3, “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 calendar month periodicity for completing a subsequent risk assessment was specified.”

- **Model Completeness:** An entity’s risk assessment is required to determine potential adverse reliability impacts to the BPS within an Interconnection. To understand whether an entity is appropriately assessing these potential impacts, CMEP staff shall review the models to ensure they are reflective of planned system conditions and include projects expected to be in service within 24 months. CMEP staff shall evaluate the strength of internal controls, including the following:
 - How an entity ensures their planned projects, as well as those of neighboring entities, will be up to date in each risk assessment. This may include entities that are in another Reliability Coordinator footprint but are electrically adjacent.
- **Model Characteristics:** CMEP staff shall analyze the selection (or lack thereof) of adjustments made to the model to better represent both existing and anticipated risks when the risk assessment is performed. It is expected that stressful system conditions on the transmission system are based on engineering knowledge from past operating conditions; scenarios from previously performed assessments; or the judgment of transmission planners performing the risk assessment for the entity’s system. Possible items for consideration are as follows:

- Summer peak and winter peak load levels
- Shoulder peak load levels with system transfers
- Alternative generation dispatch assumptions or scenarios (e.g., derating of weather-dependent resources due to low wind, or derating of natural gas resources sourced from a common pipeline)
- Alternative end-use consumer models (e.g., different penetration of inductive motor load, distributed energy resource models, or power factor improvement projects)
- Unavailability of BES Facility that has impact on risk assessment
 - An entity's spare equipment strategy could result in the unavailability of major transmission equipment that has a lead-time of one year or more (such as a transformer). The impact of this possible unavailability on System performance could be considered for study
 - Off-Peak Load models
 - High Transfer models
- **Model Appropriateness:** CMEP staff shall consider potential gaps in the selection of the model(s) used for the R1 risk assessment (i.e., creation date and year represented) and the timing required to perform subsequent risk assessments from R1.1 (i.e., 30 calendar months or 60 calendar months). When selecting which model to use for the R1 risk assessment, it is recommended for the entity to select a case that most closely aligns with the timing in R1.1 (i.e., 30 calendar months or 60 calendar months). While the entity is required to include all planned projects that are expected to be in service within 24 months, there are no statements in the Reliability Standard pertaining to the inclusion of planned projects that are not expected to be in service within 24 months. Consider an entity that uses their Year-5 base case for their R1 risk assessment and must perform their subsequent risk assessment within 30 or 60 months (depending on the results of their previous risk assessment per R1.1). By using a 5-year model, this entity is including projects that may or may not be in-service before their next required risk assessment. The inclusion of projects in excess of the time between risk assessments may impact the identification of Transmission station(s) and Transmission substation(s) as critical.
 - CMEP staff shall understand the approach the entity has taken for projects that have been included within the risk assessment that are in excess of the time for the entity's next risk assessment and if the entity is aware of how those projects impacted the results of its assessment.
 - Based on auditor judgment, discussions with the entity may involve differences between the current risk assessment and past risk assessment, such as planned projects included in both assessments, projects planned to be in service after the date of their next planned risk assessment, and what issues those projects are expected to resolve.
 - Further, CMEP staff shall consider the fidelity of the model provided for such projects planned in service in excess of the time for the entity's next risk assessment. Potential gaps exist where the following is true:

- Project model(s) do not align with most recent project status (e.g., 50 MW solar photovoltaic plant versus 50 MW solar photovoltaic and hybrid battery energy storage system facility)
- Default parameterized generic models are used in place of project-specific parameters.
 - Requesting a comparison of the steady state and dynamic results used in the current risk assessment to the results of previous risk assessment studies (Transmission station(s) and Transmission substation(s) that were significantly closer to study thresholds in previous risk assessment studies may be relatively more impacted by planned projects.)
 - Requesting the entity share results of their steady state and dynamic studies to show what impacts the removal of certain planned projects (in excess of the time between risk assessment) may have on the identification of critical Transmission station(s) and Transmission substation(s) (Consider reviewing selections based on the scope of those future project(s) to evaluate only the impact of larger projects rather than all applicable planned projects.)

Technical Analyses

The language within R1 states the following:

“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.”

While this language affords entities the flexibility in developing specifics of their own risk assessments, it is incumbent upon the entity to perform a “transmission analysis or transmission analyses” that identifies those Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged would maintain system Stability and not result in uncontrolled separation or Cascading within an Interconnection

Supporting Technical material

The entity should have developed a technical basis for the types of analysis required to ensure the system maintains Stability and does not result in Cascading or uncontrolled separation. Additional technical supplemental information for **System Stability Analysis**, **Uncontrolled Separation Assessment**, and **Cascading Analysis** are provided later in this section.

- CMEP staff shall verify an entity can clearly demonstrate, through its analysis, that instability, uncontrolled separation, and Cascading within the Interconnection was or was not identified within the Interconnection.
 - Identify the process used to perform these analyses and ensure that the process accounts for instability, uncontrolled separation, and Cascading within the Interconnection.
 - Identify the technical definitions for instability, uncontrolled separation, and Cascading within the Interconnection and ensure that each condition is considered adequately in the risk assessment.

- Identify how an entity ensures that the Interconnection is studied by their selection of monitored Facilities. Examples that elicit further examination include the following:
 - An entity only monitoring their own buses.
 - An entity only monitoring buses within their own Reliability Coordinator footprint.
- CMEP staff shall ascertain whether the entity is relying on the results of past studies to conduct its current risk assessment. The use of past studies should include a technical justification for why the entity determines it is appropriate to use a past study, a means to validate the technical justification, and this justification aligns with the entity’s documented method for material changes.
- CMEP staff shall understand the entity’s rationale for selecting the study assumptions (e.g., base case loading conditions, stress patterns, season, and special scenarios); this includes any supporting analyses, such as determination of sensitivity cases, to demonstrate impacts of changes to the basic assumptions used.

System Stability Analysis

Power system Stability is generally discussed as one concept; however, due to the complexity and large number of variables in a typical power system, power system Stability is often classified by categories or types of Stability. **Figure 1** shows a categorization of stability studies adopted from a publication by IEEE/CIGRE⁹. Categories of Stability are based on the electrical, mechanical, and magnetic response of the power system due to a Contingency that may result in the system’s inability to return to a stable operating condition. NERC’s Glossary of Terms can help in this regard, as the term; Stability refers to “the ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.” A common approach to proving power system Stability is through proof by contrapositive in which the power system is proved to be stable by first demonstrating that it is not unstable in each of the categories in **Figure 1**.

These categories are further broken down into sub-categories that are often based on the time frame for which these instabilities could occur (e.g., short term vs. long term). Each distinct sub-category of Stability is then categorized by the types of tools and techniques used to study that particular type of electrical, mechanical, and magnetic response. Classification of the different types of Stability and their assessment are discussed in more detail below.

⁹ https://e-cigre.org/publication/ELT_208_10-definition-and-classification-of-power-system-stability

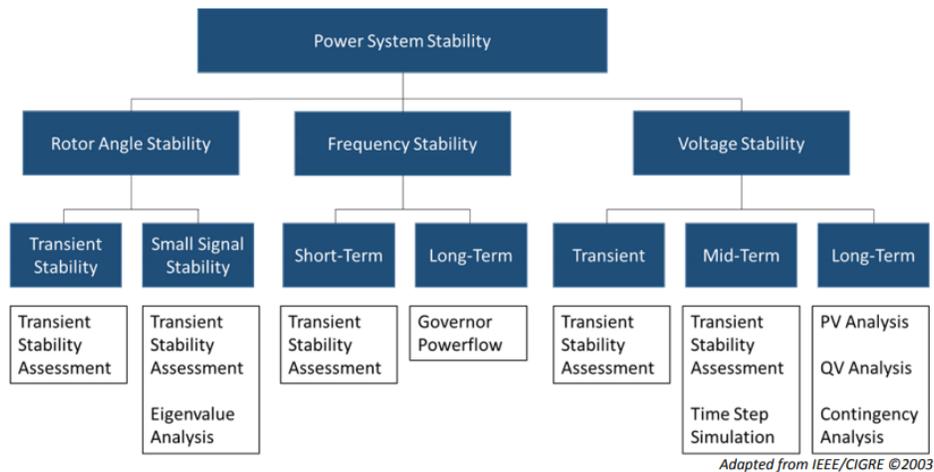


Figure 1: Generic Overview of Power System Stability¹⁰

To assure system Stability is retained, CMEP staff should review whether some type of rotor angle Stability, frequency Stability, and voltage Stability analysis addressing the loss or partial loss of the Transmission station or Transmission substation was performed. CMEP staff should verify that power system stability was assessed, which is typically accomplished via dynamic studies. CMEP staff shall use the following to assess if the technical rationale associated with each of the components in **Figure 1** ensures sufficient coverage for the Stability assessment.¹¹

- For rotor angle Stability:
 - Did the process prove that the power system was able to return to a stable operating condition when studying the angular swings of a disturbance?
 - Does the simulated rotor mechanical speed remain within logical boundaries?
 - Do any simulated generators “lose synchronism”? If so, does the process study their tripping, loss, and further subsequent effect on angular swings?
 - Are any sustained rotor oscillations dampened (decreasing in sinusoidal amplitude over every period)?
 - Are there other questions to address synchronizing and damping torque?
 - For portions of the system with high levels of Inverter-Based Resources, the mechanical terminology of classical rotor angle Stability is not always directly applicable. These resources can, however, impact the power system’s rotor angle Stability and provide stabilizing power. Further, their controls can also introduce angular instability not associated with rotor position.

¹⁰ Adopted for NERC Reliability Guideline: Methods for Establishing IROLs:

https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_Methods_for_Establishing_IROLs.pdf
https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_Methods_for_Establishing_IROLs.pdf

¹¹ Note that a single “run” of a transient Stability assessment can cover multiple aspects depending on its setup, but the supplied information should directly address which portion of Stability the “run” addresses.

A study that proves no rotor angle instability must also prove no angular instability from these resources.

- For frequency Stability:
 - Does the power system return to a stable operating condition within acceptable criteria from any generation tripped from Transmission station or Transmission substation?
 - Does the power system return to a stable operating condition within acceptable criteria from any load reduction or losses associated with the loss or partial loss of the elements in question?
 - Can the generation fleet sustain the altered power requirements during the arresting, primary, secondary, and tertiary periods after the disturbance?
- For voltage Stability, note that this type of Stability can have a PV, QV, or other graph associated with it in the long-term time frame that can prove there is no voltage instability (which, by contraposition, means there is voltage Stability) by demonstrating there is a margin to the nose of that curve after the loss or partial loss of the elements in question.
 - How does the reactive capability of the power system result in it returning to a stable operating point within acceptable voltage limits?
 - Does the process clearly articulate the acceptable voltage limits?
 - Do all load buses follow the above criteria in the simulation?

Uncontrolled Separation Assessment

Uncontrolled separation refers to the unintended islanding of a portion of an electric system that includes generation, load, or a combination of the two.¹² Unintended refers to the unplanned removal of a portion of the electric system due to operation of protection or control systems. Uncontrolled separation occurs when studies indicate that a contingency is expected to trigger relay action that causes the system to break apart into islands in an unintended (non-deliberate) manner (e.g., the operation of transmission (or generation) protection systems that completely isolated the transmission circuits connecting two portions of the BES caused by a contingency in one of the portions). This would be considered uncontrolled separation since the operation of the relays was not intended and created two electrical islands. The identification of potential actions from protection schemes, Remedial Action Schemes (RAS), and other control systems is needed when classifying a separation as uncontrolled versus controlled.

Such identification of actions from protection schemes, RASs, and other control systems that could lead to uncontrolled separation is not a trivial task. Demonstrating controlled separation requires knowledge of the conditions for which those systems actuate. Separation events are considered uncontrolled until otherwise proven by study to be controlled through operation of protection systems, RASs, or other control systems intentionally used to separate portions of the system.

¹² It is relevant to note that these islands can also be unstable and any one of them can either maintain or lose energization of the facilities. This is different than the consequential loss of generation or load due to the disturbance and isolating any faulted equipment and such distinctions should be clear in the process providing evidence for CIP-014.

Uncontrolled separation is a challenging concept to study since it can be contributory or a result of instability or Cascading and is difficult to simulate. **Figure 2** shows an overall flowchart for analyzing separation events. The contingency event is simulated and results obtained. Assuming that some type of separation is identified in the simulation results, it then must be determined whether or not the separation was a controlled separation or an uncontrolled separation. When the separation is considered to be an uncontrolled separation, it violates one of the conditions of R1 in CIP-014-3 and is deemed a station that if rendered inoperable or damaged could result uncontrolled separation. Evidence supporting the classification of uncontrolled or controlled separation should relate to language in **Figure 2**.

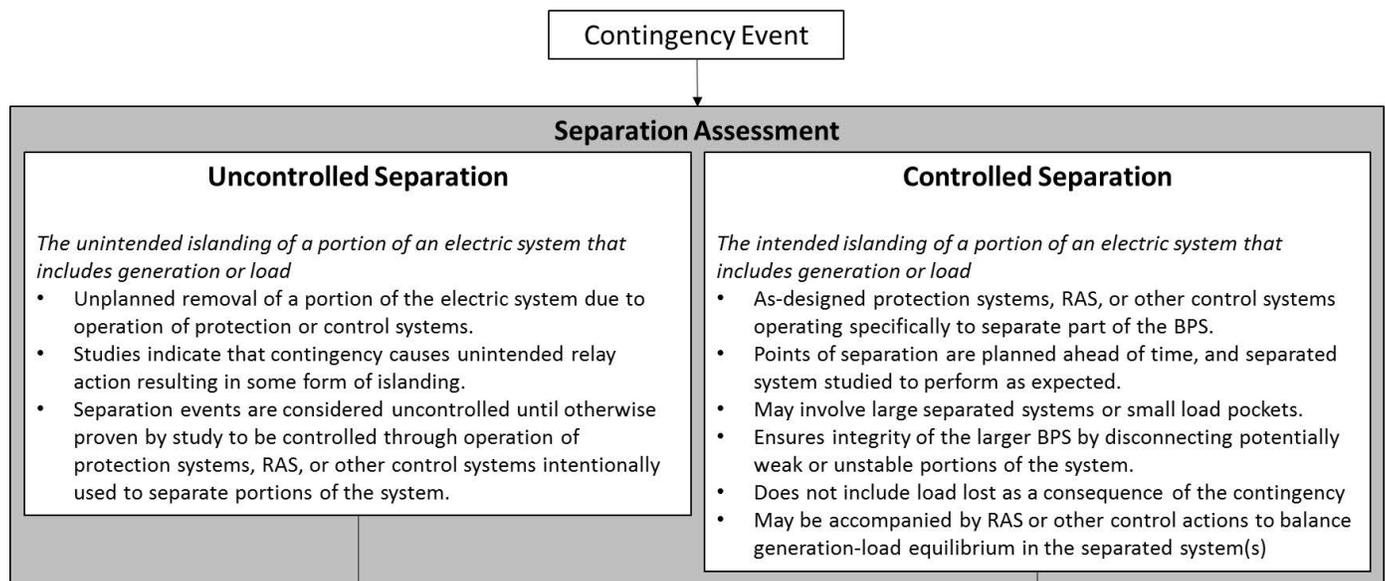


Figure 2: Controlled vs. Uncontrolled Separation¹³

Cascading Analysis

Cascading analysis studies the successive loss of system elements. There should be a strong technical basis for the thresholds used to instigate a successive tripping of elements in the studies of Cascading and whether that Cascading has a sufficiently large impact to establish an IROL. This technical basis should take into account the following considerations at a minimum:

- Facility ratings
- Generator relay loadability
- Transmission relay loadability

Tripping of successive elements to simulate Cascading is performed in an iterative process. **Figure 3** provides one possible flowchart that, at a minimum, be used for Cascading analysis. Entities may consider slight modifications to this process that strengthen the analysis. This could include analyzing power flow solution mismatches as well as incorporating Stability simulations as part of the Cascading analysis.

¹³ NERC Reliability Guideline: Methods for Establishing IROLs:
https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_Methods_for_Establishing_IROLs.pdf

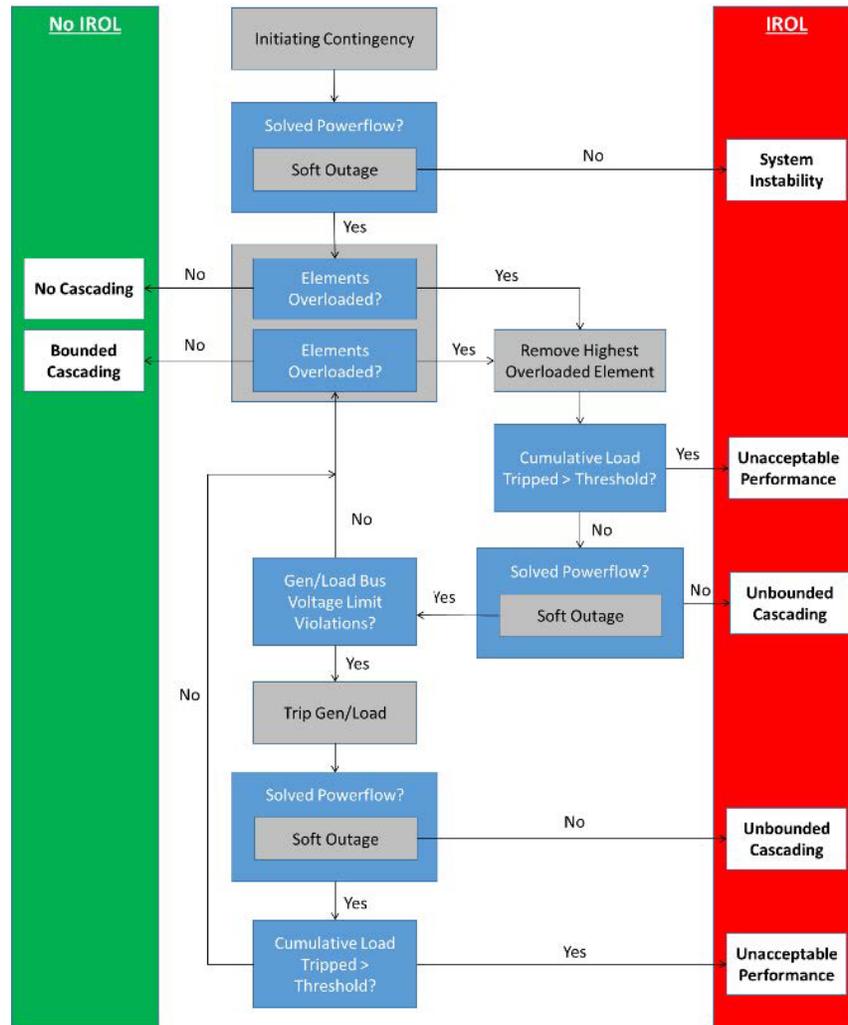


Figure 3: Cascading Analysis Process Chart¹⁴

Steady-State Power Flow Considerations

When an entity performs a **steady-state power flow** to identify thermal overloads and abnormal voltage conditions post-contingency, adequate criteria should be built into the risk assessment and should be documented clearly. These criteria are most applicable to Cascading analysis to determine the risk of subsequent element tripping in steady state.

- CMEP staff shall understand the development process and rationale for selecting steady-state criteria to evaluate instability, uncontrolled separation, and Cascading within the Interconnection.

¹⁴ The term “soft outage” is used here consistent with the [NERC Reliability Guideline: Methods for Establishing IROLs](#). From the document (page 53) “A “soft outage” approach may be employed as the analysis approaches the point of instability (nose of the P-V curve) when a contingency causes the powerflow solution to diverge due to voltage collapse (or for potential numerical instability)... As the “soft outage” is applied, the load pocket is connected through one remaining transmission circuit that is unable to serve the load. The voltages within the load pocket drop significantly while voltages outside the pocket remain near nominal (within acceptable limits).”

- CMEP staff shall evaluate the development process and rationale for steady-state criteria by considering the following:
 - **Thermal criteria:** Criteria used for determining Cascading are clearly defined and justified. For example, if 120 percent of a Facility rating used to identify Cascading (subsequent outage of element), determine why that threshold was selected.
 - **Voltage criteria:** Voltage exceedance thresholds should be clearly defined and justified based on the entity's actual protection system responses.
 - **Relay loadability criteria:** An entity may incorporate relay loadability data into its determination or selection of criteria. This may include considerations of protection systems or other types of tripping that could contribute to Cascading.
 - **Co-opted criteria:** Entities may prefer to follow a method or criteria as provided by their Reliability Coordinator. In these cases, the entity's decisions for criteria should be clear to CMEP staff selection in addition to the source for their criteria.
 - **Consistency between criteria:** An entity that also performs transmission-planning functions may technically justify the use of criteria that is different from what applied to the CIP-014-3 R1 risk assessment, such as its transmission planning criteria or IROL method. Differences between these types of applied criteria should be clear to CMEP staff.
- CMEP staff shall verify that the base case(s) used in the R1 risk assessment converge and verify the solution results are within the entity's documented criteria. This can be performed through a sampling of select Transmission station(s) and Transmission substation(s).
- CMEP staff shall ascertain if entities have clear documentation regarding how to handle non-convergence cases. Without a clear method and supporting technical justification, non-convergence in steady state is considered unacceptable.
 - In the rare occurrence that the entity has unavoidable instances of non-convergence in its solution sets, such as for issues in the Interconnection model outside of the entity's responsibility, CMEP staff shall understand how the entity's implemented method was able to effectively assess system conditions and determine if there were no adverse impacts to the Interconnection. This should be done with subsequent studies.
 - It should be recommended to the entity to develop branch thermal exceedance thresholds, bus voltage exceedance thresholds, load loss thresholds, or generation loss thresholds should any such thresholds not be part of the entity's documented criteria.

Dynamic Simulation Considerations

An entity performs dynamic simulations to assess BPS responses from the state change following an event, or studied set of contingencies. Adequate criteria should be clearly documented in the risk assessment to evaluate this stage change and detect issues, such as unstable power swings (oscillations); generator rotor angle instability; voltage excursions beyond the entity's criteria; and potential transient tripping following a fault or other contingency event. The time frame of dynamic simulations ranges from a few seconds to over a minute depending on the sequence of potential Cascading or instability events.

- CMEP staff shall consider the following to assess the development process and rationale for selecting dynamic criteria to evaluate instability, uncontrolled separation, and Cascading within the Interconnection:
 - Type of fault: Entities should provide rationale for the combinations of events studied in dynamic simulations, such as the type of fault used in their analysis.
 - Per R1, the entity is required to perform an “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.” CMEP staff shall verify how the entity simulates a physical event whereby the entire Transmission station or Transmission substation is rendered inoperable or damaged.
 - CMEP staff shall understand the entity’s assumptions and modeling practices for studies to achieve the requirements of the Standard while recalling that the end result is maintaining Stability and assuring there is no uncontrolled separation or Cascading.
 - CMEP staff shall understand the derivation of criteria an entity is using for fault clearing times for all monitored Facilities, including those external to its system. The loss of local protection system(s) due to the loss of the Transmission station or Transmission substation may require the usage of only delayed (remote) clearing times unless otherwise technically substantiated.
 - Co-opted criteria: Entities may prefer to follow a method or criteria as provided by their Reliability Coordinator. In these cases, the entity’s decisions for criteria selection should be clear to CMEP staff in addition to the source for the criteria.
 - Consistency between criteria: An entity that also performs transmission-planning functions may use criteria for the CIP-014-3 R1 risk assessment that is different from what applied to other transmission planning studies, such as an IROL methodology. CMEP staff shall understand the technical justification for differences between these types of applied criteria.
 - The selected model(s) should solve within reasonable tolerance that uses sound engineering judgment based on the planning criteria set forth in the methodology by the Planning Coordinator, Transmission Planner, and/or the Transmission Owner. Indicators for sound engineering judgment includes a process for evaluating the solution parameters for steady state and dynamic analyses as well as thermal and voltage violations in the N-0 or non-contingent conditions before performing the risk assessment. If the Transmission Owner develops, its own user-based models or made changes to existing model types, the adequacy criteria review associated with those customized models should be more robust and assess the impact of those modifications.
- Additional criteria: Entities may include additional criteria in consideration of UVLS/UFLS and RASs as well as load and generation loss. The development and selection of these criteria should be clear to CMEP staff. Based on auditor judgment, additional steps may include the following:
 - To verify that the base case(s) used in the R1 risk assessment converge and to verify that the solution results are within the entity’s documented criteria.

- To request an SME demonstrate the results for a sampled selection of Transmission station(s) and Transmission substation(s) to confirm those results.

ERO Endorsed Implementation Guidance

- NATF CIP 014-2 Requirement R1 Guideline:
[https://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/CIP-014-2%20R1%20Guideline%20\(NATF\).pdf](https://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/CIP-014-2%20R1%20Guideline%20(NATF).pdf)

Additional References

- ASIS International, Facilities Physical Security Measure Guideline:
<https://www.asisonline.org/publications/sg-asis-facilities-physical-security-measures-guideline-2009-ed/>
- ASIS International, General Risk Assessment Guidelines:
<https://www.asisonline.org/publications/sg-asis-general-security-risk-assessment-guideline/>
- ASIS International, Security Management Standard: Physical Asset Protection:
<https://www.asisonline.org/publications/sg-asis-security-management-standard-physical-asset-protection/>
- North American Electric Reliability Corporation Security Guideline for the Electricity Sector: Physical Security:
https://www.nerc.com/comm/CIPC_Security_Guidelines_DL/Physical_Security_Guideline_%20Assessments_and_Resiliency_Measures_for_Extreme_Events_June_2019.pdf
- NERC Methods for Establishing IROs Task Force: IROL Framework Assessment Report:
https://www.nerc.com/comm/PC/Methods%20for%20Establishing%20IROs%20Joint%20Task%20Force%20ME/MEITF_IROL_Framework_Assessment_-_2018-08-21.pdf

Revision History

Revision #	Revision Date	Revision Details
V1.0	11/18/21	Initial Draft
V1.1	09/21/22	Guidance clarification in Technical Analysis section