NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface

to ensure
the reliability of the
bulk power system

November 16, 2009

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Executive Summary

Conclusions

1. Generator Interconnection Facilities operating at a voltage of 100 kV or greater or those deemed critical to the Bulk Electric System by the Regional Entity makes the Generator Interconnection Facility part of the Bulk Electric System for purposes of applying Generator Owner and Generator Operator requirements but not for applying Transmission Owner or Transmission Operator requirements.

2. The Generator Owner or Generator Operator that owns and/or operates a Generator Interconnection Facility, that is, a sole-use facility that interconnects the generator to the grid, should not be registered as a Transmission Owner or Transmission Operator by virtue of owning or operating its Generator Interconnection Facility.

3. A Generator Interconnection Facility is considered as though part of the generating facility specifically for purposes of applying Reliability Standards to a Generator Owner or Generator Operator.

4. Changes to NERC Reliability Standards are needed to ensure complete reliability coverage of the Generator Interconnection Facility.

    a. 32 NERC Reliability Standard requirements contain language regarding generators or generating facilities for which greater clarity regarding its Generator Interconnection Facilities would ensure that no reliability gap exists.

    b. 12 requirements in FAC-003-1 – Transmission Vegetation Management should have their applicability expanded to include Generator Owners.

    c. 2 NERC Reliability Standards should have their applicability expanded to include Generator Operators to address general reliability gaps not attributable to the Generator Interconnection Facility.

    d. 8 new Reliability Standard requirements should be added to ensure the responsibilities for owning and operating the Generator Interconnection Facility are clear, and to address certain requirements that should apply to all generators regardless of interconnection configuration.

5. If a generator is connected to multiple transmission facilities that are subject to network power flows (that is, power flow on these multiple transmission facilities includes power not solely associated with the generator output, requirements for station service, auxiliary load, or cogeneration load), then those transmission facilities are integrated transmission facilities and should be subjected to the applicable Transmission Owner and Transmission Operator Standard Requirements[1].

6. After review of the existing Transmission Owner requirements that are not currently applicable to Generator Owners, only FAC-003-1 should have its applicability expanded to include Generator Owners as a result of the Generator Interconnection Facility, if the length

[1] A double-circuit line behind the point of interconnection, for example, that is carrying power solely associated with the generation output, requirements for station service, auxiliary load, or cogeneration load, would not be considered an integrated transmission facility by comparison.

of the Generator Interconnection Facility exceeds two spans (generally, more than one-half mile) from the generator property line.

7. After review of the existing Transmission Operator requirements that are not currently applicable to Generator Operators, no existing Transmission Operator requirements should apply to Generator Operators as a result of the Generator Interconnection Facility.
8. New NERC Glossary definitions are needed for Generator Interconnection Facility and Generator Interconnection Operational Interface, as well as modifications to the terms Vegetation Inspection, Right-of-Way, Generator Owner, Generator Operator, and Transmission.

Recommendations

1. Submit Standards Authorization Requests (SARs) requesting expeditious action to add or modify the definitions in NERC's Glossary for Generator Interconnection Facility and Generator Interconnection Operational Interface, as well as modifications to the terms Vegetation Inspection, Right-of-Way, Generator Owner, Generator Operator, and Transmission.
2. Submit SARs requesting expeditious action to modify existing standard requirements to add specificity for Generator Interconnection Facility where appropriate, to add Generator Operator applicability where needed, to add requirements to capture responsibilities for owning and operating the Generator Interconnection Facility, and to add requirements where necessary that should be applicable to Generator Operators regardless of the interconnection configuration.
3. Modify the applicability of FAC-003-1 to apply to Generator Owners when their Generator Interconnection Facility operates at 200 kV or above and exceeds two spans from the generator property line, or otherwise is deemed to be critical to the Bulk Electric System.
4. Modify the NERC Rules of Procedure, NERC Compliance Registry Criteria, and other documents as necessary to reflect that a Generator Owner should not be registered as a Transmission Owner and a Generator Operator should not be registered as a Transmission Operator on the basis of the Generator Interconnection Facility.
5. NERC and the Regional Entities should refrain from further registering Generator Owners and Generator Operators as Transmission Owners and Transmission Operators generically by virtue of the Generator Interconnection Facility.
6. Based on the conclusions and recommendations offered in this report, NERC and the Regional Entities should carefully develop and implement a plan to address de-registering those Generator Owners and Generator Operators that have previously been registered as a Transmission Owner and Transmission Operator by virtue of the Generator Interconnection Facility.

Discussion

Historical Perspective

On January 14, 2008, the NERC Board of Trustees Compliance Committee rendered a decision upholding the Western Electricity Coordinating Council's (WECC's) determination to register the New Harquahala Generating Company ("Harquahala") as a Transmission Owner and Transmission Operator. This determination is based on Harquahala's 26-mile 500 kV interconnection facilities that connect the plant with the Hassayampa transmission substation. In its determination, NERC concluded that:

- Harquahala met its glossary definition of "Transmission Owner" and "Transmission Operator";
- Harquahala's interconnection facilities are integrated transmission elements as described in NERC's Compliance Registry because they interconnect the generating facility to the transmission grid; and,
- Harquahala as a generating facility and the transmission station to which it interconnects are material to the Bulk Power System.

As a result, NERC found that Harquahala must be registered as a Transmission Owner and Transmission Operator in order to provide for proper coordination between Harquahala and Salt River Project, owner and operator of the Hassayampa substation, and for proper operation and maintenance of the interconnection facilities. NERC stated that a reliability gap exists because several high risk Reliability Standards do not otherwise apply to Harquahala under its other registration functions including those for vegetation management; taking corrective action if a protective relay failure reduces system reliability; coordinating protection systems; analyzing protection system misoperations and developing a corrective action plan to avoid future misoperations; developing procedures for monitoring voltage levels and reactive flow; and exercising the responsibility and clear decision-making authority to take actions needed to ensure the reliability of its area and to take action to alleviate operating emergencies. NERC stated, "from a reliability perspective and from the standpoint of section 215 of the FPA, this transmission line is integrated with other elements of the [Bulk Power System] requiring coordination of operation with those other elements." NERC also noted that Harquahala's registration status is based on ownership of its generation facilities, while its Transmission Owner and Transmission Operator status are based on ownership and operation of the transmission facilities.

In its appeal to FERC, Harquahala argued that its interconnection facilities were not integrated transmission elements; that its facilities will not have a material impact on the Bulk-Power System; that registration as a Transmission Owner and Transmission Operator is unwarranted because there is no reliability gap; and that its registration as such would result in inconsistent registrations in WECC and other regions. Harquahala notably did not contest that its interconnection facilities were part of the Bulk Power System.

FERC denied Harquahala's appeal on the material impact of the assets to the reliability of the Bulk Power System, but declined to address issues regarding the NERC Compliance Registry Criteria and the definition of "integrated transmission element." FERC noted that "if Harquahala is only registered as a Generator Owner and Generator Operator, and not a Transmission Owner and Transmission Operator, it will not be required to have its staff trained and NERC-certified to operate these facilities in an emergency or to coordinate protection for its transmission line and switchyard with other transmission operators and the Regional Entity." Further, FERC noted that if adequate reliability requirements were not provided on Harquahala's tie-line, there is a reliability risk affecting a significant portion of the Bulk Power System in WECC confirming that a reliability gap exists. Significantly, FERC indicated that its finding in this case is case-specific and not one that all tie-line owners and operators should now be registered as Transmission Owners and Transmission Operators. Because Harquahala cannot physically comply with all transmission owner and transmission operator requirements in NERC standards, FERC directed NERC and Harquahala to negotiate those that will be applicable to them. This activity was completed in July, 2008.

The impact of the Harquahala registration decision manifested itself in a concern by some Generator Owners and Generator Operators regarding the criteria (or the lack thereof) that would be used to consistently determine whether other Generator Owners and Generator Operators would be also subject to registration as a Transmission Owner and Transmission Operator. In addition to the Harquahala case, there have been a small number of similar appeals to registration decisions on this issue that resulted in the registration of Generator Owners and or Generator Operators as Transmission Owners and or Operators. It is not clearly known the number of Generator Owners and Generator Operators also registered as Transmission Owners and Transmission Operators by virtue of its interconnection facilities that have chosen not to appeal.

In response to this growing concern, NERC undertook a survey in the Fall, 2008 to identify the specific nature of the concerns, to review and highlight those Transmission Owner and Transmission Operator requirements that should be considered for generic applicability to Generator Owners and Generator Operators by virtue of their interconnection facilities, and to collect ideas for how the issue could be resolved. There were wide-ranging viewpoints to the topic from the over 100 respondents but there was no support for merely assigning all Transmission Owner and Transmission Operator Requirements to the Generator Owner and Generator Operator on the basis of their interconnection facilities. One consistent suggestion was to assemble a group of industry representatives to analyze and make recommendations for resolving the issue, thereby establishing general criteria for determining whether Generator Owners and Generator Operators should be registered for Transmission Owner and Transmission Operator requirements in NERC's Reliability Standards.

Accordingly, in February, 2009, NERC announced the formation of the Ad Hoc Group for Generator Requirements at the Transmission Interface.

Team Objective

"Evaluate existing NERC Reliability Standard requirements and develop a recommendation and possible Standards Authorization Request to address gaps in reliability for interconnection facilities of the Generator Owner and expectations for the Generator Operator in operating those facilities. Propose strategies to address or resolve other related issues as appropriate."

Team Composition

The team was selected to provide a cross-section of participants across different geographic regions and industry segments, specifically linked with various NERC technical groups, and representative of both the operating and planning perspectives. The size of the team was intentionally managed to foster and efficient and effective disposition of the team's obligations. The team consisted of the following members:

Scott Helyer, Chair	Tenaska, Inc.
Steven Cobb	Salt River Project
Keith Daniel	Georgia Transmission Corporation
Jeffrey Gillen	American Transmission Corporation
Anthony Jankowski	We Energies
Gregory Mason	Dynegy
Eric Mortenson	Exelon Energy Delivery
Timothy Ponseti	Tennessee Valley Authority
Kent Saathoff	Electric Reliability Council of Texas, Inc.
Gerry Adamski	NERC Staff Coordinator

Problem Statement

The team devoted effort at the outset to clearly define and understand the problem that the team was organized to address. In this deliberation and determination, the team developed the following problem statement, assumptions, and process description that it used to guide its activities thereafter as presented in **Exhibit 1**:

Exhibit 1

Problem Statement:

Certain equipment owned and/or operated by generators may be defined as part of the Bulk Electric System. As such, the team needs to determine which owner and operating requirements are needed for reliability purposes for these facilities and then identify the functional entity[2] accountable for compliance to those requirements.

Assumptions:

1. There are pieces of equipment at 100 kV and above currently owned and operated by generators that may fall under the definition of Bulk Electric System and therefore are under the purview of the NERC Reliability Standards.
2. For pieces of equipment identified in assumption No. 1 above, at least one functional entity must be identified to be responsible for each standard requirement applicable to these facilities at an ownership and operating level, understanding that multiple ownership and operating arrangements exist.[3]
3. Separate the ownership expectations from the operating expectations in the discussion.
4. Current standard requirements assigned to Generator Owners and Generator Operators are appropriate.

Process to Address Identified Problem:

1. Review the list of standard requirements applicable to Transmission Owners and/or Transmission Operators that are not currently applicable to Generator Owners and/or Generator Operators.
2. Determine which of the Transmission Owner standard requirements not assigned to Generator Owners should always be, never be, or could possibly be assigned to address potential reliability gaps based on the equipment owned by the Generator Owner.
3. Determine which of the Transmission Operator standard requirements not assigned to Generator Operators should always be, never be, or could possibly be assigned to address potential reliability gaps based on the equipment operated by the Generator Operator.
4. Determine if these requirements are already covered by other existing reliability standard requirements.
5. If not, determine a strategy for identifying the functional entity that should be assigned the responsibility for these requirements, not necessarily limited to the current list of functional entities.

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[2] The use of the term "functional entity" is not intended to limit team consideration to those functional entities currently utilized in NERC's Reliability Standards. If in its deliberation, the team identifies a new functional entity that should be defined; the team can make such a proposal.

[3] The goal is to assign responsibility for these requirements to a single functional entity but recognize that clear delineation of these responsibilities must be identified when multiple entity arrangements apply.

6. Perform sensitivity analyses using the list of “parking lot” questions/issues to determine further activities for the team.
7. Finalize recommendations within a final report that includes potential SARs.

Issues List

The industry survey that NERC conducted in late 2008 led to the identification of 17 issues for team consideration that are presented below. This list of issues was included in the original proposal that recommended the formation of the team. The team to varying degrees addressed these issues as discussed below, and in several cases, captured the response to related issues in one response. The discussion that follows includes the summary of the team’s deliberation and the rationale for the conclusion the team reached on each issue, and any recommendations that resulted from those discussions. During the course of these discussions, the team carefully separated the impact of the generating unit itself from the impact from the generator’s interconnection facilities. Stated more specifically, the team considered whether there were certain of NERC’s existing Transmission Owner and Transmission Operator requirements that currently do not apply but should apply to the Generator Owner and or Generator Operator by virtue of the interconnection facilities that connect the generating unit to the grid and the various configurations therein. However, the team did not consider the potential loss of energy produced by the generator as a sufficient basis to apply Transmission Owner and or Transmission Operator standards to the generator. In circumstances where improvement to a requirement is needed and is applicable because of the generating plant itself and not because of the interconnection facility, the team identified the needed change and noted it as a generic generator issue. In its resolution of these issues, the team considered the owner requirements apart from the operator requirements.

1. **Identify what is needed to ensure the reliable supply of real and reactive power to the grid; and determine the goal of the Generator Owner and Generator Operator Requirements (bulk electric system reliability vs. interconnection facility reliability).**
   The team concluded that to the extent a generator’s interconnection facilities met the current NERC Glossary Definition as Bulk Electric System, that is, facilities operating above 100 kV or those deemed critical to the reliability of the Bulk Electric System as defined by the Regional Entity, then those facilities are part of the generating facility and are appropriately classified as part of the Bulk Electric System for purposes of applying Generator Owner and Generator Operator requirements, but not for applying Transmission Owner or Transmission Operator Requirements. In this construct, the Generator Owner and Generator Operator has responsibility for the Generator Interconnection Facility (as defined herein) and the Transmission Owner and Transmission Operator has responsibility for the transmission facilities that connect to the Generator Interconnection Facility, and importantly, has operating responsibility for the Generator Interconnection Operational Interface (as defined herein). This approach ensures that no reliability gap exists for the Generator Interconnection Facility. Please continue with the response to Issue 2 for further discussion on the role of Generation Owners and Operators.

2. **Affect of interconnection configuration on standard requirements and applicability**

The team discussed the varying system configurations that could exist at the generating facility end of the interconnection facility and on the transmission grid side of the interconnection facility. The team quickly concluded that the core issue was the applicability of requirements for sole-use interconnection facilities, that is, those facilities whose singular purpose is to connect the generating facility (inclusive of associated station service load, auxiliary load, or cogeneration load) to the interconnected grid. In this context, facilities such as double circuit lines or the various substation configurations that may exist at the generator facility are included as part of the Generator Interconnection Facility provided their purpose is limited to transmitting power from the plant, provision of station service, auxiliary load requirements, or provision of cogeneration load requirements. For other configurations in which the interconnection facility is used by other parties to tie to other substations or to customer loads or where a generator is connected to multiple transmission facilities of other parties, these facilities are considered integrated for the purposes of standard applicability and the full spectrum of Transmission Owner and Transmission Operator requirements would apply as appropriate.

The team also concluded that an outage of the Generator Interconnection Facility that results in an outage of an integrated transmission line (such as exists in a three-terminal or T-tap configuration) does not provide a sufficient basis for making the Generator Interconnection Facility subject to Transmission Owner and Transmission Operator standard requirements. In fact, the NERC Statement of Compliance Registry Criteria (Revision 5.0) includes an exclusion from registration for "radial transmission facilities serving only load with one transmission source" which would include similar configurations such as T-taps or three-terminal lines. In the case of radial facilities serving only load, the obligations for PRC-type requirements, for example, are included by virtue of the registration as another functional entity besides a Transmission Owner (for instance, as a Distribution Provider assuming the entity meets the Registry criteria for such inclusion). Similarly, Generator Owners that meet the Registry criteria will necessarily be responsible for relevant PRC-type requirements.

Considering sole-use interconnection facilities, the team determined that greater specificity in the current standards is necessary to clearly define and identify Generator Interconnection Facility "as a recognized term and to apply the term where appropriate in certain of the requirements to ensure a clear understanding of expectations. The team therefore proposes below to add a definition of Generator Interconnection Facility to the NERC Glossary and several changes to requirements to include this term. Similarly, the team recommends a proposed new definition and application of the term "Generator Interconnection Operational Interface" in the NERC Glossary and in several standard requirements.

The team also considered various scenarios pertaining to the relationship of the Generator Owner to the Transmission Owner regarding the interconnection facility equipment. If a Generator Owner owns the physical equipment that resides in the Transmission Owner substation at the Generator Interconnection Operational Interface, the team believed that the Generator Owner would not have the independent ability to access or affect the equipment without interfacing with the Transmission Owner; rather, the Generator Owner would necessarily have to coordinate with the Transmission Owner to gain access to the station and work under escort to perform activities on the equipment it owned. As a result, the team believes that in this scenario, the Generator Owner should not be required to be registered as a Transmission Owner directly.

When viewed at the operational level, considerable discussion ensued regarding the relationship between the Generator Operator and Transmission Operator for operation of the Generator Interconnection Facility, that is, the sole-use interconnection facility. While generally accepted that the Generator Owner owns the Generator Interconnection Facility, the team recognized that the Generator Operator over the facility must use reasonable means to coordinate the operation of that facility in order to preserve the reliability of the grid to which it is interconnected, when the facility is energized and synchronized to the grid or when the interconnection facility is about to be de-energized from or re-energized to the transmission system[4]. The Generator Operator must understand the potential impact to the interconnected transmission system for the actions that they perform on the Generator Interconnection Facility and must therefore be provided focused training for the reliable execution of those responsibilities. Importantly, however, the Transmission Operator to whom the Generator Interconnection Facility interconnects has the decision-making operational authority over the Generator Interconnection Operational Interface.

In response to comments received during the public posting of the initial report, the team also discussed the treatment of the Generator Interconnection Facility of small generators not registered as a Generator Owner and Generator Operator. The team concluded that to the extent that a Regional Entity believes that a small generator and/or its Generator Interconnection Facility is material to the reliability of the Bulk Electric System, it has the right to make such a demonstration and propose registration of the entity as a Generator Owner and Generator Operator. In fact, this report's conclusion that the Generator Interconnection Facility is considered part of the generating facility may benefit 1) the Regional Entity in making a demonstration of materiality as well as 2) the generator if such a demonstration is made. In this regard, the Regional Entity will be able to make its demonstration of materiality on the basis of the generating facility (which includes the Generator Interconnection Facility) instead of having to make separate materiality demonstrations for both the generating unit(s) and the Generator Interconnection Facility. Therefore, if a small generating facility and its Generator Interconnection Facility are demonstrated to be material to the reliability of the Bulk Electric System, they would then be registered as a Generator Owner and Generator Operator and subject to Generator Owner and Generator Operator standards but not subject to Transmission Owner and Transmission Operator standard requirements.

The approach posited in this report acknowledges that the Generator Interconnection Facility, as defined herein, functions for a singular and well-defined purpose, to transmit power to and from the generating plant and for purposes of station service, auxiliary load requirements, or for cogeneration load. As such, these facilities are different in usage than transmission facilities that comprise the interconnected grid. The team carefully reviewed all Transmission Owner requirements for application to the Generator Interconnection Facility and recommend adjustments to several requirements to clarify expectations for the Generator

[4] Except for situations involving imminent equipment damage or personnel safety for which the Generator Operator may be required to act without coordination with the Transmission Operator.

Owners. Thus, the team believes that these changes ensure consistent expectations at an ownership level. At an operating level, a number of Transmission Operator requirements exist for operating an interconnected transmission grid and a number of closely related Generator Operator requirements are applicable to the Generator Interconnection Facility based on the recommendations contained in this report. Additionally, in a similar fashion to the exclusion provided to radial transmission serving only load in the existing NERC definition of Bulk Electric System and that pertaining to of the inclusion of distribution provider facilities involved in underfrequency load shedding, the Generator Interconnection Facility is proposed to be addressed by NERC standards based on their use Accordingly, the approach proposed implements a strategy to ensure no gaps in reliability coverage exist relative to the Generator Interconnection Facility. By virtue of the recommendation to process the standard changes using the NERC *Reliability Standard Development Procedure*, the specific approach contained herein will be further vetted with ample opportunity for stakeholder review, input, modification as necessary, and approval before implementation.

3. **Review GO/GOP and TO/TOP Requirements to identify reliability gaps**
The group spent a significant amount of time reviewing first the Transmission Owner requirements, and then the Transmission Operator requirements currently approved for enforcement but not currently applicable to the Generator Owners or Generator Operators. This bifurcated review carefully considered whether a specific requirement should be made applicable to the Generator Owner or Generator Operator solely on the basis of the Generator Interconnection Facility, and not on the basis of the generator itself. In conducting this review, it became apparent to the team that certain requirements presented a potential reliability gap because the Generator Operator was not listed as an applicable entity based on the generator itself (but not because of its interconnection facility). The team also carefully reviewed the Generator Owner and Generator Operator requirements and concluded that the responsibilities for owning and operating the Generator Interconnection Facility could best be clarified by making certain Generator Owner and Generator Operator requirement language more specific to include the term "Generator Interconnection Facility". The redline changes to the NERC Standards that highlight these changes are included in **Appendix 1**.

The following description summarizes the proposed standard requirement changes.

- The team identified 32 requirements in which the Generator Interconnection Facility is specifically added to the requirement.
- The team identified 12 requirements in FAC-003-1 – Transmission Vegetation Management that need to include the Generator Owner as an applicable entity based on the conclusions discussed later in the report.
- The team noted 2 requirements whose applicability should be expanded to address generic issues associated with the generating facility and not necessarily with respect to the Generator Interconnection Facility.
- The team identified the need to add 8 new standard requirements to fully clarify the expectations with regard to the Generator Interconnection Facility, heretofore implied in the Standards, or to address certain requirements that should apply to all generators regardless of interconnection configuration as follows.

1. The Generator Operator who has responsibility for monitoring the status of a special protection system or remedial action scheme at the generating facility for the benefit of Bulk Electric System reliability should notify the Transmission Operator when a change in status or capability occurs.
2. Each Generator Operator shall provide its operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and the Generation Interconnection Facility, and to implement directives of the Transmission Operator and Balancing Authority.
3. Each Generator Operator shall implement an initial and continuing training program for all personnel responsible for operating the Generator Interconnection Facility to ensure the ability to operate the equipment in a reliable manner.
4. The Generator Operator shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects to preserve Interconnection reliability.
5. The Transmission Operator has decision-making authority for the Generator Interconnection Operational Interface.
6. The Generator Operator shall notify the Transmission Operator of a change in status of the Generation Interconnection Facility.
7. The Generator Operator shall operate the Generation Interconnection Facility within Facility Ratings.
8. The Generator Operator shall disconnect the Generation Interconnection Facility immediately in coordination with the Transmission Operator when time permits or as soon as practical thereafter if an overload or other abnormal condition threatens equipment or personnel safety.

Regarding item new requirement No. 3, the team does not intend that this requirement results in a need for NERC-certified transmission or generator operators at the generating plant by virtue of the Generator Interconnection Facility. Rather, the training program must contain the necessary elements for the Generator Operator tasked with operating the Generator Interconnection Facility to understand fully the impacts of their operation on the Bulk Electric System, such as equipment involved, including relaying, the coordination aspects with the Transmission Operator to which it is connected, and the protocols for and impacts of operating facilities associated with the Generator Interconnection Facility, including the Generator Interconnection Operational Interface. The objective of this training is to ensure that the Generator Operator is completely aware of its obligations to the Transmission Operators and has the skills and training to execute these obligations in the best interest of reliability.

In completing the review of standard requirements and the determination therein of needed changes, the team concluded that there was no basis for assigning existing Transmission Owner and Transmission Operator standard requirements to the Generator Owner and

Generator Operator, respectively, solely on the basis of the Generator Interconnection Facility, with one exception. The team believes that Standard FAC-003 (Vegetation Management) should apply to Generator Owners of a Generator Interconnection Facility whose facilities operate at 200 kV and above or are otherwise deemed critical to the Bulk Electric System and whose Generation Interconnection Facility exceeds two spans (generally one-half mile from the generator property line). In reaching this conclusion, the team considered other options that included inclusion of Generator Owners as applicable entities to FAC-003 based on a test for criticality, or to include Generator Owners as applicable entities in the existing version of FAC-003 without modification to the applicability criteria. The team, supported by a majority of industry commenters indicated the two-span test presented a simple and objective method to determine responsibilities for Generator Owners. Additionally, the "200 kV and above, or otherwise deemed critical to the Bulk Electric System" threshold is consistent with the current applicability of FAC-003 to Transmission Owners. The rationale for the selection of the two-span criteria is that this distance is in the generator operator's line-of-sight and as such could be visually monitored for vegetation conditions on a routine basis, and beyond which distance a vegetation management program would be necessary for the Right-of-Way.

In addition regarding the applicability of FAC-003, the group agreed that all units designated as a blackstart resource that are material to and designated as part of the Transmission Operator's system restoration plan, irrespective of voltage level, are deemed to be critical for purposes of FAC-003 application to the Generator Interconnection Facility, subject to the two-span criterion. To be material, a blackstart unit is defined as a unit that is part of a system restoration plan's facilities that are used to initiate system restoration and establish the basic minimum power system following a blackout.

4. **Defining functional lines of demarcation between the Generator Owner and the Transmission Owner**
   The team agrees that the Generator Owner owns the Generator Interconnection Facility and the Transmission Owner owns the facilities of the interconnection grid to which the Generator Interconnection Facility connects. Also agreed is that clear operating responsibility must exist for these facilities. In order to clearly articulate the point at which the change of operation occurs between the Generator Operator and Transmission Operator, the team proposes to add a new definition to the NERC Glossary for Generator Interconnection Operational Interface. The new definition is: location at which operating responsibility for the Generator Interconnection Facility changes from the Transmission Operator and the Generator Operator.

5. **Impact of operational control or ownership of equipment in the transmission substation containing the generator interconnection facilities**
   This issue is addressed in the Issue 2.

6. **Effect of FERC-filed Interconnection Agreements and other agreements between GO/GOP and the TO/TOP**
   Depending on the vintage, FERC-filed Interconnection Agreements outline to varying degrees the operating and ownership relationship between the Transmission Provider and the

Interconnection Customer (e.g. Generating Facility). However, the Interconnection Agreements address the expectations for entities under its jurisdiction with respect to different sections of the Federal Power Act than Section 215 that addresses reliability and defines a broader applicability. Therefore, there is an inconsistency in the scope of the entities for which Interconnection Agreements are required and those under Section 215 of the Federal Power Act for reliability purposes. Additionally, the functional entity names in NERC Reliability Standards do not match those terms in the Interconnection Agreements. For these reasons, the effect of Interconnection Agreements on NERC's Standards is debatable.

In addition, NERC's Reliability Standards must contain the requirements necessary to ensure an adequate level of reliability for the Bulk Electric System. It is not appropriate for NERC to rely on other agreements as the primary vehicle to define reliability obligations. Thus, while the Interconnection Agreements may define greater specificity as to how certain reliability-related activities are expected to be conducted, NERC Reliability Standards must contain what is required from a performance outcome. The team has evaluated the current set of requirements to validate that the necessary requirements are in place; and to the extent improvements or additions are needed, identified those modifications or new obligations.

7. **Bifurcated review of GO Requirements and GOP Requirements**
The team agreed that it is necessary and appropriate to consider the Generator Owner Requirements distinct from the Generator Operator requirements as discussed in Issue 3.

8. **Review NERC Glossary definitions for Transmission, Generator Owner, Generator Operator, Transmission Owner, and Transmission Operator**
The team reviewed the definitions listed in the NERC Glossary of Terms and considered additional terms as they impacted the intent and meaning of certain requirements currently applicable to the Transmission Operator or Transmission Owner. The team believed that modifications to some and additions of several new terms were needed to add greater clarity to the applicability of requirements pertaining to the generator interconnection facilities.

    - Transmission — the team agreed with the existing definition but determined it necessary to add a sentence to specify that the Generator Interconnection Facility is not part of the definition. The proposed definition with the modification italicized is as follows:

      Transmission
      An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems. *Generator Interconnection Facility is not included in this definition.*

    - Generator Owner — the team agreed with the existing definition but determined it necessary to add a phrase that specifies the inclusion of the generator's interconnection facilities. The proposed definition is as follows:

Generator Owner
Entity that owns and maintains generating units*, including its Generator Interconnection Facility*

- Generator Operator — the team agreed with the existing definition but determined it necessary to add a sentence to indicate that operational coordination was necessary with the Transmission Operator for the Generator Interconnection Facility. With the modification italicized, the proposed definition is:

Generator Operator
The entity that operates generating unit(s) and the Generator Interconnection Facility and performs the functions of supplying energy and Interconnected Operations Services. *The Generator Operator also operates the Generator Interconnection Facility and is responsible for coordinating with the Transmission Operator when the facility is energized or about to be energized to/de-energized from the transmission system.*

- Transmission Owner — no changes are necessary
- Transmission Operator — no changes are necessary

The team also considered the terms, Transmission Line, Element, Facility, Interconnection, and System and do not recommend changes to these terms. Further, the team recommends improvements to the terms, Right-of-Way and Vegetation Inspection to encompass the Generator Interconnection Facility, and proposes two new terms, Generator Interconnection Facility and Generator Interconnection Operational Interface as follows:

Right-of-Way (ROW)
A corridor of land on which electric lines may be located. The ~~Transmission Owner~~ *owner of the electric lines* may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

Vegetation Inspection
The systematic examination of a ~~transmission corridor~~ *Transmission Line or Generator Interconnection Facility Right-of-Way* to document vegetation conditions.

Generator Interconnection Facility (NEW)
Sole-use facility for the purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility only transmits power associated with the interconnecting generator, whether delivered to the grid or delivered to the generator for station service or auxiliary load, or delivered to meet cogeneration load requirements.

Generator Interconnection Operational Interface (NEW)
Location at which operating responsibility for the Generator Interconnection Facility changes between the Transmission Operator and the Generator Operator.

These terms will be incorporated as recommended changes to existing standard requirements through the standards authorization requests contained in Appendix C.

9. **NERC Compliance Registry Guidance**
The team identified that companion changes to NERC's Statement of Compliance Registry are required to incorporate the changes to the definitions for Generator Owner and Generator Operator proposed by the group. As outlined in Exhibit B, specific modifications are required in Section II of the document with respect to the definitions of Generator Owner and Generator Operator as proposed in this report. Additional changes are necessary in Section III.c.4 and III.d.2 to provide the proposed definition of Generator Interconnection Facility and to specify that the Generator Interconnection Facility is considered part of the generating facility and not the integrated transmission system for purposes of applying the registry criteria.

In addition, the group believes it appropriate to include definitive statements such that it is clear that a Generator Owner or Generator Operator should not be registered as a Transmission Owner or Transmission Operator, respectively, solely resulting from the Generator Interconnection Facility as defined herein. These modifications will ensure consistency in application of the NERC Reliability Standards to those Generator Owners identified through implementation of the NERC Compliance Registry processes.

In addition, NERC and the Regional Entities should carefully develop and implement a plan to address de-registering those Generator Owners and Generator Operators that have previously been registered as a Transmission Owner and Transmission Operator by virtue of the Generator Interconnection Facility. The team recognizes that Regional Entities have discretion to determine critical facilities within its footprint in individual case-by-case assessments.

10. **Material Impact Test for Generator Interconnection Facilities**
The group concluded that only one existing Reliability Standard that is applicable to Transmission Owners, FAC-003-1, should have its applicability expanded to Generator Owners because of their Generator Interconnection Facility. Although the two-span test noted in Proposal 2 was selected as the most appropriate approach, the following list contains a summary of the three proposals that were considered:

Proposal 1 — A straightforward criterion suggested is to apply FAC-003-1 for the Generator Interconnection Facility per the current standard's applicability.

Proposal 2 — A second proposal is based on Proposal 1 but provides an exclusion for short distance Rights-of-Way that are generally within line of sight from the generating plant. This proposal calls for applying FAC-003-1 for the Generator Interconnection Facility operating above 200 kV that extend beyond two tower spans (i.e. ½ mile) from the generating plant property line.

Proposal 3 — A third proposal applies FAC-003-1 to the Generator Interconnection Facility that operates at 200 kV or above and that is deemed critical to the Bulk Electric System. In this regard, the criticality test as discussed by the team would be the following: the Generator Owner would coordinate with the Transmission Planner to perform an impact based test utilizing similar criteria to that outlined in TPL-003-0 Table 1 Category C that assesses system performance under scenarios involving more than one contingency event. Particularly, the team agreed that the engineering analysis would be based on the system performance expectations of a single-line-to-ground fault on the interconnection facility with delayed clearing or a stuck breaker. Under these conditions, the criticality test would be met if the system response to these contingency events resulted in cascading outages, system instability, or operating outside applicable ratings, with loss of firm load or the curtailment of third-party firm transfers that is not associated with the loss of the generating plant output directly connected to the Generator Interconnection Facility against which the originating contingency was applied.

The team ultimately relied on additional input received from industry stakeholders during the comment opportunity to guide its conclusion in this area. Based on the simplicity and objectiveness of approach, a large number of commenters indicated a preference for Proposal 2. While the criticality test was supported by some, most expressed concern regarding the resource commitment for analysis and the subjectivity of the approach.

11. **Functionality test — Does the facility function as part of the generator function or the transmission function**
    Because the generator owns the Generator Interconnection Facility, the team decided that a Generator Interconnection Facility is considered part of the generator facility. For clarity, a number of standard requirement modifications or additions are recommended to ensure that the Generator Interconnection Facility is appropriately considered and that clear responsibility for ownership and operation are established by those identified as having these obligations.

12. **Approach for multi-unit plants interconnected through a single transmission line**
    The team considered this issue and supported its earlier determination that a sole-use interconnection facility should not in and of itself require a Generator Owner and Generator Operator to be registered as a Transmission Owner and Transmission Operator.

13. **Generic application of requirements versus a case-by-case determination**
    The team determined that through addition or modification of certain standard requirements, there is no reliability gap by virtue of the Generator Interconnection Facility with one exception: FAC-003-1 pertaining to transmission vegetation management. The team determined that FAC-003-1 standard should apply to Generator Owners for facilities operating above 200 kV or otherwise deemed critical to the Bulk Electric System if the Generation Interconnection Facility exceeds two-spans, generally one-half mile, from the generator property line. Otherwise, the standards as modified provide the ability to generically apply the standard requirements to all Generator Owners and Generator Operators without introducing or perpetuating any perceived reliability gaps.

14. **Affect on the applicability if generators provide ancillary services (reactive control, regulation, reserves, etc.)**

This issue is addressed previously and is at the discretion of Regional Entities in application of the definition of Bulk Electric System.

15. Consideration of generators that are included in:

- special protection scheme or remedial action scheme
- coordinated underfrequency program
- coordinated undervoltage program
- blackstart
- SOL or IROL limits
- Provision of firm energy

This issue is addressed previously and is at the discretion of Regional Entities in application of the definition of Bulk Electric System.

16. Need for additional maintenance-based generator owner requirements on interconnection facilities when generators already are financially incented to remain available

The team concluded that to the extent a generator's interconnection facilities meet the current NERC Glossary Definition as Bulk Electric System, that is, facilities operating above 100 kV or those deemed critical to the reliability of the Bulk Electric System as defined by the Regional Entity, then those facilities are appropriately classified as part of the Bulk Electric System for purposes of applying Generator Owner and Generator Operator requirements but not for applying Transmission Owner or Transmission Operator requirements For interconnection facilities classified as such, an entity must be designated to be responsible for relevant ownership and operation obligations. These obligations manifest themselves as requirements in the Reliability Standards to ensure an adequate level of reliability is maintained on the Bulk Electric System. Therefore, specification of ownership and operational requirements for a Generator Interconnection Facility is necessary to ensure the expected performance is achieved consistent with the reliability objectives being sought. While the statement is undoubtedly true that generators, including its interconnection facilities, are motivated to remain available to be capable of delivering energy (and capacity) to the grid, these self-directed motivations do not adequately assure that the obligations for reliability of the Bulk Electric System will be supported under all circumstances. Developing NERC Reliability Standard requirements to address these expectations further incent the Generator Owner and Generator Operator to execute their responsibilities consistent with NERC's reliability obligations.

17. Develop new transmission functional category know as Generator-Tie

The team considered whether the addition of a new Generator-Tie functional category would add the clarity needed to ensure that standard requirements applicable to generator interconnection facilities would result in no reliability gaps. Upon reflection, the team determined that it could achieve the intended purpose through the inclusion the modified and new definitions proposed, and their application to the existing standard requirements. This would result in significantly less effort to implement in the standards, greater industry acceptance, and thus a shorter timeframe to implement on the whole.

Appendix 1 — Review of NERC Reliability Standards Requirements

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
BAL-005-0.1b	R1.	All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.		GOP		TOP	
BAL-005-0.1b	R1.1.	Each Generator Operator with generation facilities, including its Generator Interconnection Facility, operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.		GOP			
BAL-005-0.1b	R1.2.	Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.				TOP	
CIP-001-1	R1.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi site sabotage affecting larger portions of the Interconnection.		GOP		TOP	
CIP-001-1	R2.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection.		GOP		TOP	
CIP-001-1	R3.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall provide its operating personnel with sabotage response guidelines, including personnel to contact, for reporting disturbances due to sabotage events.		GOP		TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-001-1	R4.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity shall establish communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop reporting procedures as appropriate to their circumstances.		GOP		TOP	
CIP-002-1	R1.	Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.	GO	GOP	TO	TOP	
CIP-002-1	R1.1.	The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.	GO	GOP	TO	TOP	
CIP-002-1	R1.2.	The risk-based assessment shall consider the following assets:	GO	GOP	TO	TOP	
CIP-002-1	R1.2.1.	Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.	GO	GOP	TO	TOP	
CIP-002-1	R1.2.2.	Transmission substations that support the reliable operation of the Bulk Electric System.	GO	GOP	TO	TOP	
CIP-002-1	R1.2.3.	Generation resources, including the Generator Interconnection Facility, that support the reliable operation of the Bulk Electric System.	GO	GOP	TO	TOP	
CIP-002-1	R1.2.4.	Systems and facilities critical to system restoration, including blackstart generators and their attendant Generator Interconnection Facility, and substations in the electrical path of transmission lines used for initial system restoration.	GO	GOP	TO	TOP	
CIP-002-1	R1.2.5.	Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.	GO	GOP	TO	TOP	
CIP-002-1	R1.2.6.	Special Protection Systems that support the reliable	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		operation of the Bulk Electric System.					
CIP-002-1	R1.2.7.	Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.	GO	GOP	TO	TOP	
CIP-002-1	R2.	Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.	GO	GOP	TO	TOP	
CIP-002-1	R3.	Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:	GO	GOP	TO	TOP	
CIP-002-1	R3.1.	The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,	GO	GOP	TO	TOP	
CIP-002-1	R3.2.	The Cyber Asset uses a routable protocol within a control center; or,	GO	GOP	TO	TOP	
CIP-002-1	R3.3.	The Cyber Asset is dial-up accessible.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-002-1	R4.	Annual Approval — A senior manager or delegate(s) shall approve annually the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)	GO	GOP	TO	TOP	
CIP–003–1	R1.	Cyber Security Policy — The Responsible Entity shall document and implement a cyber security policy that represents management's commitment and ability to secure its Critical Cyber Assets. The Responsible Entity shall, at minimum, ensure the following:	GO	GOP	TO	TOP	
CIP–003–1	R1.1.	The cyber security policy addresses the requirements in Standards CIP-002 through CIP-009, including provision for emergency situations.	GO	GOP	TO	TOP	
CIP–003–1	R1.2.	The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.	GO	GOP	TO	TOP	
CIP–003–1	R1.3.	Annual review and approval of the cyber security policy by the senior manager assigned pursuant to R2.	GO	GOP	TO	TOP	
CIP–003–1	R2.	Leadership — The Responsible Entity shall assign a senior manager with overall responsibility for leading and managing the entity's implementation of, and adherence to, Standards CIP-002 through CIP-009	GO	GOP	TO	TOP	
CIP–003–1	R2.1.	The senior manager shall be identified by name, title, business phone, business address, and date of designation.	GO	GOP	TO	TOP	
CIP–003–1	R2.2.	Changes to the senior manager must be documented within thirty calendar days of the effective date.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP–003–1	R2.3.	The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy.	GO	GOP	TO	TOP	
CIP–003–1	R3.	Exceptions — Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and authorized by the senior manager or delegate(s).	GO	GOP	TO	TOP	
CIP–003–1	R3.1.	Exceptions to the Responsible Entity's cyber security policy must be documented within thirty days of being approved by the senior manager or delegate(s).	GO	GOP	TO	TOP	
CIP–003–1	R3.2.	Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating measures, or a statement accepting risk.	GO	GOP	TO	TOP	
CIP–003–1	R3.3.	Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Such review and approval shall be documented.	GO	GOP	TO	TOP	
CIP–003–1	R4.	Information Protection — The Responsible Entity shall implement and document a program to identify, classify, and protect information associated with Critical Cyber Assets.	GO	GOP	TO	TOP	
CIP–003–1	R4.1.	The Critical Cyber Asset information to be protected shall include, at a minimum and regardless of media type, operational procedures, lists as required in Standard CIP-002, network topology or similar diagrams, floor plans of computing centers that contain Critical Cyber Assets, equipment layouts of Critical Cyber Assets, disaster recovery plans, incident response plans, and security configuration information.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP–003–1	R4.2.	The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.	GO	GOP	TO	TOP	
CIP–003–1	R4.3.	The Responsible Entity shall, at least annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment results, and implement an action plan to remediate deficiencies identified during the assessment.	GO	GOP	TO	TOP	
CIP–003–1	R5.	Access Control — The Responsible Entity shall document and implement a program for managing access to protected Critical Cyber Asset information.	GO	GOP	TO	TOP	
CIP–003–1	R5.1.	The Responsible Entity shall maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.	GO	GOP	TO	TOP	
CIP–003–1	R5.1.1.	Personnel shall be identified by name, title, business phone and the information for which they are responsible for authorizing access.	GO	GOP	TO	TOP	
CIP–003–1	R5.1.2.	The list of personnel responsible for authorizing access to protected information shall be verified at least annually.	GO	GOP	TO	TOP	
CIP–003–1	R5.2.	The Responsible Entity shall review at least annually the access privileges to protected information to confirm that access privileges are correct and that they correspond with the Responsible Entity's needs and appropriate personnel roles and responsibilities.	GO	GOP	TO	TOP	
CIP–003–1	R5.3.	The Responsible Entity shall assess and document at least annually the processes for controlling access privileges to protected information.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP–003–1	R6.	Change Control and Configuration Management — The Responsible Entity shall establish and document a process of change control and configuration management for adding, modifying, replacing, or removing Critical Cyber Asset hardware or software, and implement supporting configuration management activities to identify, control and document all entity or vendor related changes to hardware and software components of Critical Cyber Assets pursuant to the change control process.	GO	GOP	TO	TOP	
CIP-004-1	R1.	Awareness — The Responsible Entity shall establish, maintain, and document a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access receive on-going reinforcement in sound security practices. The program shall include security awareness reinforcement on at least a quarterly basis using mechanisms such as: Direct communications (e.g., emails, memos, computer based training, etc.); Indirect communications (e.g., posters, intranet, brochures, etc.); Management support and reinforcement (e.g., presentations, meetings, etc.).	GO	GOP	TO	TOP	
CIP-004-1	R2.	Training — The Responsible Entity shall establish, maintain, and document an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and review the program annually and update as necessary.	GO	GOP	TO	TOP	
CIP-004-1	R2.1.	This program will ensure that all personnel having such access to Critical Cyber Assets, including contractors and service vendors, are trained within ninety calendar days of such authorization.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-004-1	R2.2.	Training shall cover the policies, access controls, and procedures as developed for the Critical Cyber Assets covered by CIP-004, and include, at a minimum, the following required items appropriate to personnel roles and responsibilities:	GO	GOP	TO	TOP	
CIP-004-1	R2.2.1.	The proper use of Critical Cyber Assets;	GO	GOP	TO	TOP	
CIP-004-1	R2.2.2.	Physical and electronic access controls to Critical Cyber Assets;	GO	GOP	TO	TOP	
CIP-004-1	R2.2.3.	The proper handling of Critical Cyber Asset information; and,	GO	GOP	TO	TOP	
CIP-004-1	R2.2.4.	Action plans and procedures to recover or re-establish Critical Cyber Assets and access thereto following a Cyber Security Incident.	GO	GOP	TO	TOP	
CIP-004-1	R2.3.	The Responsible Entity shall maintain documentation that training is conducted at least annually, including the date the training was completed and attendance records.	GO	GOP	TO	TOP	
CIP-004-1	R3.	Personnel Risk Assessment —The Responsible Entity shall have a documented personnel risk assessment program, in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements, for personnel having authorized cyber or authorized unescorted physical access. A personnel risk assessment shall be conducted pursuant to that program within thirty days of such personnel being granted such access. Such program shall at a minimum include:	GO	GOP	TO	TOP	
CIP-004-1	R3.1.	The Responsible Entity shall ensure that each assessment conducted include, at least, identity verification (e.g., Social Security Number verification in the U.S.) and seven year criminal check. The Responsible Entity may conduct more detailed reviews, as permitted by law and subject to existing	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		collective bargaining unit agreements, depending upon the criticality of the position.					
CIP-004-1	R3.2.	The Responsible Entity shall update each personnel risk assessment at least every seven years after the initial personnel risk assessment or for cause.	GO	GOP	TO	TOP	
CIP-004-1	R3.3.	The Responsible Entity shall document the results of personnel risk assessments of its personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and that personnel risk assessments of contractor and service vendor personnel with such access are conducted pursuant to Standard CIP-004.	GO	GOP	TO	TOP	
CIP-004-1	R4.	Access — The Responsible Entity shall maintain list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets.	GO	GOP	TO	TOP	
CIP-004-1	R4.1.	The Responsible Entity shall review the list(s) of its personnel who have such access to Critical Cyber Assets quarterly, and update the list(s) within seven calendar days of any change of personnel with such access to Critical Cyber Assets, or any change in the access rights of such personnel. The Responsible Entity shall ensure access list(s) for contractors and service vendors are properly maintained.	GO	GOP	TO	TOP	
CIP-004-1	R4.2.	The Responsible Entity shall revoke such access to Critical Cyber Assets within 24 hours for personnel terminated for cause and within seven calendar days for personnel who no longer require such access to Critical Cyber Assets.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-005-1	R1.	Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s).	GO	GOP	TO	TOP	
CIP-005-1	R1.1.	Access points to the Electronic Security Perimeter(s) shall include any externally connected communication end point (for example, dial-up modems) terminating at any device within the Electronic Security Perimeter(s).	GO	GOP	TO	TOP	
CIP-005-1	R1.2.	For a dial-up accessible Critical Cyber Asset that uses a non-routable protocol, the Responsible Entity shall define an Electronic Security Perimeter for that single access point at the dial-up device.	GO	GOP	TO	TOP	
CIP-005-1	R1.3.	Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s).	GO	GOP	TO	TOP	
CIP-005-1	R1.4.	Any non-critical Cyber Asset within a defined Electronic Security Perimeter shall be identified and protected pursuant to the requirements of Standard CIP-005.	GO	GOP	TO	TOP	
CIP-005-1	R1.5.	Cyber Assets used in the access control and monitoring of the Electronic Security Perimeter(s) shall be afforded the protective measures as a specified in Standard CIP-003, Standard CIP-004 Requirement R3, Standard CIP-005 Requirements R2 and R3, Standard CIP-006 Requirements R2 and R3, Standard CIP-007, Requirements R1 and R3 through R9, Standard CIP-008, and Standard CIP-009.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-005-1	R1.6.	The Responsible Entity shall maintain documentation of Electronic Security Perimeter(s), all interconnected Critical and non-critical Cyber Assets within the Electronic Security Perimeter(s), all electronic access points to the Electronic Security Perimeter(s) and the Cyber Assets deployed for the access control and monitoring of these access points.	GO	GOP	TO	TOP	
CIP-005-1	R2.	Electronic Access Controls — The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).	GO	GOP	TO	TOP	
CIP-005-1	R2.1.	These processes and mechanisms shall use an access control model that denies access by default, such that explicit access permissions must be specified.	GO	GOP	TO	TOP	
CIP-005-1	R2.2.	At all access points to the Electronic Security Perimeter(s), the Responsible Entity shall enable only ports and services required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter, and shall document, individually or by specified grouping, the configuration of those ports and services.	GO	GOP	TO	TOP	
CIP-005-1	R2.3.	The Responsible Entity shall maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s).	GO	GOP	TO	TOP	
CIP-005-1	R2.4.	Where external interactive access into the Electronic Security Perimeter has been enabled, the Responsible Entity shall implement strong procedural or technical controls at the access points to ensure authenticity of the accessing party, where technically feasible.	GO	GOP	TO	TOP	
CIP-005-1	R2.5.	The required documentation shall, at least, identify and describe:	GO	GOP	TO	TOP	
CIP-005-1	R2.5.1.	The processes for access request and authorization.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-005-1	R2.5.2.	The authentication methods.	GO	GOP	TO	TOP	
CIP-005-1	R2.5.3.	The review process for authorization rights, in accordance with Standard CIP-004 Requirement R4.	GO	GOP	TO	TOP	
CIP-005-1	R2.5.4.	The controls used to secure dial-up accessible connections.	GO	GOP	TO	TOP	
CIP-005-1	R2.6.	Appropriate Use Banner — Where technically feasible, electronic access control devices shall display an appropriate use banner on the user screen upon all interactive access attempts. The Responsible Entity shall maintain a document identifying the content of the banner.	GO	GOP	TO	TOP	
CIP-005-1	R3.	Monitoring Electronic Access — The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging access at access points to the Electronic Security Perimeter(s) twenty-four hours a day, seven days a week.	GO	GOP	TO	TOP	
CIP-005-1	R3.1.	For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall implement and document monitoring process(es) at each access point to the dial-up device, where technically feasible.	GO	GOP	TO	TOP	
CIP-005-1	R3.2.	Where technically feasible, the security monitoring process(es) shall detect and alert for attempts at or actual unauthorized accesses. These alerts shall provide for appropriate notification to designated response personnel. Where alerting is not technically feasible, the Responsible Entity shall review or otherwise assess access logs for attempts at or actual unauthorized accesses at least every ninety calendar days.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-005-1	R4.	Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of the electronic access points to the Electronic Security Perimeter(s) at least annually. The vulnerability assessment shall include, at a minimum, the following:	GO	GOP	TO	TOP	
CIP-005-1	R4.1.	A document identifying the vulnerability assessment process;	GO	GOP	TO	TOP	
CIP-005-1	R4.2.	A review to verify that only ports and services required for operations at these access points are enabled;	GO	GOP	TO	TOP	
CIP-005-1	R4.3.	The discovery of all access points to the Electronic Security Perimeter;	GO	GOP	TO	TOP	
CIP-005-1	R4.4.	A review of controls for default accounts, passwords, and network management community strings; and,	GO	GOP	TO	TOP	
CIP-005-1	R4.5.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.	GO	GOP	TO	TOP	
CIP-005-1	R5.	Documentation Review and Maintenance — The Responsible Entity shall review, update, and maintain all documentation to support compliance with the requirements of Standard CIP-005.	GO	GOP	TO	TOP	
CIP-005-1	R5.1.	The Responsible Entity shall ensure that all documentation required by Standard CIP-005 reflect current configurations and processes and shall review the documents and procedures referenced in Standard CIP-005 at least annually.	GO	GOP	TO	TOP	
CIP-005-1	R5.2.	The Responsible Entity shall update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-005-1	R5.3.	The Responsible Entity shall retain electronic access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008.	GO	GOP	TO	TOP	
CIP-006-1	R1.	Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:	GO	GOP	TO	TOP	
CIP-006-1	R1.1.	Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.	GO	GOP	TO	TOP	
CIP-006-1	R1.2.	Processes to identify all access points through each Physical Security Perimeter and measures to control entry at those access points.	GO	GOP	TO	TOP	
CIP-006-1	R1.3.	Processes, tools, and procedures to monitor physical access to the perimeter(s).	GO	GOP	TO	TOP	
CIP-006-1	R1.4.	Procedures for the appropriate use of physical access controls as described in Requirement R3 including visitor pass management, response to loss, and prohibition of inappropriate use of physical access controls.	GO	GOP	TO	TOP	
CIP-006-1	R1.5.	Procedures for reviewing access authorization requests and revocation of access authorization, in accordance with CIP-004 Requirement R4.	GO	GOP	TO	TOP	
CIP-006-1	R1.6.	Procedures for escorted access within the physical security perimeter of personnel not authorized for unescorted access.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-006-1	R1.7.	Process for updating the physical security plan within ninety calendar days of any physical security system redesign or reconfiguration, including, but not limited to, addition or removal of access points through the physical security perimeter, physical access controls, monitoring controls, or logging controls.	GO	GOP	TO	TOP	
CIP-006-1	R1.8.	Cyber Assets used in the access control and monitoring of the Physical Security Perimeter(s) shall be afforded the protective measures specified in Standard CIP-003, Standard CIP-004 Requirement R3, Standard CIP-005 Requirements R2 and R3, Standard CIP-006 Requirement R2 and R3, Standard CIP-007, Standard CIP-008 and Standard CIP-009.	GO	GOP	TO	TOP	
CIP-006-1	R1.9.	Process for ensuring that the physical security plan is reviewed at least annually.	GO	GOP	TO	TOP	
CIP-006-1	R2.	Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. The Responsible Entity shall implement one or more of the following physical access methods:	GO	GOP	TO	TOP	
CIP-006-1	R2.1.	Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another.	GO	GOP	TO	TOP	
CIP-006-1	R2.2.	Special Locks: These include, but are not limited to, locks with “restricted key” systems, magnetic locks that can be operated remotely, and “man-trap” systems.	GO	GOP	TO	TOP	
CIP-006-1	R2.3.	Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-006-1	R2.4.	Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.	GO	GOP	TO	TOP	
CIP-006-1	R3.	Monitoring Physical Access — The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized access attempts shall be reviewed immediately and handled in accordance with the procedures specified in Requirement CIP-008. One or more of the following monitoring methods shall be used:	GO	GOP	TO	TOP	
CIP-006-1	R3.1.	Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate notification to personnel responsible for response.	GO	GOP	TO	TOP	
CIP-006-1	R3.2.	Human Observation of Access Points: Monitoring of physical access points by authorized personnel as specified in Requirement R2.3.	GO	GOP	TO	TOP	
CIP-006-1	R4.	Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:	GO	GOP	TO	TOP	
CIP-006-1	R4.1.	Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-006-1	R4.2.	Video Recording: Electronic capture of video images of sufficient quality to determine identity.	GO	GOP	TO	TOP	
CIP-006-1	R4.3.	Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R2.3.	GO	GOP	TO	TOP	
CIP-006-1	R5.	Access Log Retention — The Responsible Entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008.	GO	GOP	TO	TOP	
CIP-006-1	R6.	Maintenance and Testing — The Responsible Entity shall implement a maintenance and testing program to ensure that all physical security systems under Requirements R2, R3, and R4 function properly. The program must include, at a minimum, the following:	GO	GOP	TO	TOP	
CIP-006-1	R6.1.	Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.	GO	GOP	TO	TOP	
CIP-006-1	R6.2.	Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R6.1.	GO	GOP	TO	TOP	
CIP-006-1	R6.3.	Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.	GO	GOP	TO	TOP	
CIP-007-1	R1.	Test Procedures — The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber Assets within the Electronic Security Perimeter do not adversely affect existing cyber security controls. For purposes of Standard CIP-007, a significant change shall, at a minimum, include implementation of security patches, cumulative service packs, vendor releases, and version upgrades of operating systems, applications, database platforms,	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		or other third-party software or firmware.					
CIP-007-1	R1.1.	The Responsible Entity shall create, implement, and maintain cyber security test procedures in a manner that minimizes adverse effects on the production system or its operation.	GO	GOP	TO	TOP	
CIP-007-1	R1.2.	The Responsible Entity shall document that testing is performed in a manner that reflects the production environment.	GO	GOP	TO	TOP	
CIP-007-1	R1.3.	The Responsible Entity shall document test results.	GO	GOP	TO	TOP	
CIP-007-1	R2.	Ports and Services — The Responsible Entity shall establish and document a process to ensure that only those ports and services required for normal and emergency operations are enabled.	GO	GOP	TO	TOP	
CIP-007-1	R2.1.	The Responsible Entity shall enable only those ports and services required for normal and emergency operations.	GO	GOP	TO	TOP	
CIP-007-1	R2.2.	The Responsible Entity shall disable other ports and services, including those used for testing purposes, prior to production use of all Cyber Assets inside the Electronic Security Perimeter(s).	GO	GOP	TO	TOP	
CIP-007-1	R2.3.	In the case where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure or an acceptance of risk.	GO	GOP	TO	TOP	
CIP-007-1	R3.	Security Patch Management — The Responsible Entity, either separately or as a component of the documented configuration management process specified in CIP-003 Requirement R6, shall establish and document a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		Perimeter(s).					
CIP-007-1	R3.1.	The Responsible Entity shall document the assessment of security patches and security upgrades for applicability within thirty calendar days of availability of the patches or upgrades.	GO	GOP	TO	TOP	
CIP-007-1	R3.2.	The Responsible Entity shall document the implementation of security patches. In any case where the patch is not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure or an acceptance of risk.	GO	GOP	TO	TOP	
CIP-007-1	R4.	Malicious Software Prevention — The Responsible Entity shall use anti-virus software and other malicious software ("malware") prevention tools, where technically feasible, to detect, prevent, deter, and mitigate the introduction, exposure, and propagation of malware on all Cyber Assets within the Electronic Security Perimeter(s).	GO	GOP	TO	TOP	
CIP-007-1	R4.1.	The Responsible Entity shall document and implement anti-virus and malware prevention tools. In the case where anti-virus software and malware prevention tools are not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure or an acceptance of risk.	GO	GOP	TO	TOP	
CIP-007-1	R4.2.	The Responsible Entity shall document and implement a process for the update of anti-virus and malware prevention "signatures." The process must address testing and installing the signatures.	GO	GOP	TO	TOP	
CIP-007-1	R5.	Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access authentication of, and accountability for, all user activity, and that minimize the risk of unauthorized system access.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-007-1	R5.1.	The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of “need to know” with respect to work functions performed.	GO	GOP	TO	TOP	
CIP-007-1	R5.1.1.	The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003 Requirement R5.	GO	GOP	TO	TOP	
CIP-007-1	R5.1.2.	The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user account access activity for a minimum of ninety days.	GO	GOP	TO	TOP	
CIP-007-1	R5.1.3.	The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003 Requirement R5 and Standard CIP-004 Requirement R4.	GO	GOP	TO	TOP	
CIP-007-1	R5.2.	The Responsible Entity shall implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account privileges including factory default accounts.	GO	GOP	TO	TOP	
CIP-007-1	R5.2.1.	The policy shall include the removal, disabling, or renaming of such accounts where possible. For such accounts that must remain enabled, passwords shall be changed prior to putting any system into service.	GO	GOP	TO	TOP	
CIP-007-1	R5.2.2.	The Responsible Entity shall identify those individuals with access to shared accounts.	GO	GOP	TO	TOP	
CIP-007-1	R5.2.3.	Where such accounts must be shared, the Responsible Entity shall have a policy for managing the use of such accounts that limits access to only those with authorization, an audit trail of the account use (automated or manual), and steps for securing the account in the event of personnel changes (for example, change in assignment or termination).	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-007-1	R5.3.	At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:	GO	GOP	TO	TOP	
CIP-007-1	R5.3.1.	Each password shall be a minimum of six characters.	GO	GOP	TO	TOP	
CIP-007-1	R5.3.2.	Each password shall consist of a combination of alpha, numeric, and “special” characters.	GO	GOP	TO	TOP	
CIP-007-1	R5.3.3.	Each password shall be changed at least annually, or more frequently based on risk.	GO	GOP	TO	TOP	
CIP-007-1	R6.	Security Status Monitoring — The Responsible Entity shall ensure that all Cyber Assets within the Electronic Security Perimeter, as technically feasible, implement automated tools or organizational process controls to monitor system events that are related to cyber security.	GO	GOP	TO	TOP	
CIP-007-1	R6.1.	The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.	GO	GOP	TO	TOP	
CIP-007-1	R6.2.	The security monitoring controls shall issue automated or manual alerts for detected Cyber Security Incidents.	GO	GOP	TO	TOP	
CIP-007-1	R6.3.	The Responsible Entity shall maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in Standard CIP-008.	GO	GOP	TO	TOP	
CIP-007-1	R6.4.	The Responsible Entity shall retain all logs specified in Requirement R6 for ninety calendar days.	GO	GOP	TO	TOP	
CIP-007-1	R6.5.	The Responsible Entity shall review logs of system events related to cyber security and maintain records documenting review of logs.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-007-1	R7.	Disposal or Redeployment — The Responsible Entity shall establish formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005.	GO	GOP	TO	TOP	
CIP-007-1	R7.1.	Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.	GO	GOP	TO	TOP	
CIP-007-1	R7.2.	Prior to redeployment of such assets, the Responsible Entity shall, at a minimum, erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.	GO	GOP	TO	TOP	
CIP-007-1	R7.3.	The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures.	GO	GOP	TO	TOP	
CIP-007-1	R8.	Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of all Cyber Assets within the Electronic Security Perimeter at least annually. The vulnerability assessment shall include, at a minimum, the following:	GO	GOP	TO	TOP	
CIP-007-1	R8.1.	A document identifying the vulnerability assessment process;	GO	GOP	TO	TOP	
CIP-007-1	R8.2.	A review to verify that only ports and services required for operation of the Cyber Assets within the Electronic Security Perimeter are enabled;	GO	GOP	TO	TOP	
CIP-007-1	R8.3.	A review of controls for default accounts; and,	GO	GOP	TO	TOP	
CIP-007-1	R8.4.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP-007-1	R9.	Documentation Review and Maintenance — The Responsible Entity shall review and update the documentation specified in Standard CIP-007 at least annually. Changes resulting from modifications to the systems or controls shall be documented within ninety calendar days of the change.	GO	GOP	TO	TOP	
CIP–008–1	R1.	Cyber Security Incident Response Plan — The Responsible Entity shall develop and maintain a Cyber Security Incident response plan. The Cyber Security Incident Response plan shall address, at a minimum, the following:	GO	GOP	TO	TOP	
CIP–008–1	R1.1.	Procedures to characterize and classify events as reportable Cyber Security Incidents.	GO	GOP	TO	TOP	
CIP–008–1	R1.2.	Response actions, including roles and responsibilities of incident response teams, incident handling procedures, and communication plans.	GO	GOP	TO	TOP	
CIP–008–1	R1.3.	Process for reporting Cyber Security Incidents to the Electricity Sector Information Sharing and Analysis Center (ES ISAC). The Responsible Entity must ensure that all reportable Cyber Security Incidents are reported to the ES ISAC either directly or through an intermediary.	GO	GOP	TO	TOP	
CIP–008–1	R1.4.	Process for updating the Cyber Security Incident response plan within ninety calendar days of any changes.	GO	GOP	TO	TOP	
CIP–008–1	R1.5.	Process for ensuring that the Cyber Security Incident response plan is reviewed at least annually.	GO	GOP	TO	TOP	
CIP–008–1	R1.6.	Process for ensuring the Cyber Security Incident response plan is tested at least annually. A test of the incident response plan can range from a paper drill, to a full operational exercise, to the response to an actual incident.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
CIP–008–1	R2.	Cyber Security Incident Documentation — The Responsible Entity shall keep relevant documentation related to Cyber Security Incidents reportable per Requirement R1.1 for three calendar years.	GO	GOP	TO	TOP	
CIP–009–1	R1.	Recovery Plans — The Responsible Entity shall create and annually review recovery plan(s) for Critical Cyber Assets. The recovery plan(s) shall address at a minimum the following:	GO	GOP	TO	TOP	
CIP–009–1	R1.1.	Specify the required actions in response to events or conditions of varying duration and severity that would activate the recovery plan(s).	GO	GOP	TO	TOP	
CIP–009–1	R1.2.	Define the roles and responsibilities of responders.	GO	GOP	TO	TOP	
CIP–009–1	R2.	Exercises — The recovery plan(s) shall be exercised at least annually. An exercise of the recovery plan(s) can range from a paper drill, to a full operational exercise, to recovery from an actual incident.	GO	GOP	TO	TOP	
CIP–009–1	R3.	Change Control — Recovery plan(s) shall be updated to reflect any changes or lessons learned as a result of an exercise or the recovery from an actual incident. Updates shall be communicated to personnel responsible for the activation and implementation of the recovery plan(s) within ninety calendar days of the change.	GO	GOP	TO	TOP	
CIP–009–1	R4.	Backup and Restore — The recovery plan(s) shall include processes and procedures for the backup and storage of information required to successfully restore Critical Cyber Assets. For example, backups may include spare electronic components or equipment, written documentation of configuration settings, tape backup, etc.	GO	GOP	TO	TOP	
CIP–009–1	R5.	Testing Backup Media — Information essential to recovery that is stored on backup media shall be tested at least annually to ensure that the information is	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		available. Testing can be completed off site.					
COM-001-1	R1.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide adequate and reliable telecommunications facilities for the exchange of Interconnection and operating information:				TOP	
COM-001-1.1	R1.1.	Internally.				TOP	
COM-001-1.1	R1.2.	Between the Reliability Coordinator and its Transmission Operators and Balancing Authorities.				TOP	
COM-001-1.1	R1.3.	With other Reliability Coordinators, Transmission Operators, and Balancing Authorities as necessary to maintain reliability.				TOP	
COM-001-1.1	R1.4.	Where applicable, these facilities shall be redundant and diversely routed.				TOP	
COM-001-1.1	R2.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall manage, alarm, test and/or actively monitor vital telecommunications facilities. Special attention shall be given to emergency telecommunications facilities and equipment not used for routine communications.				TOP	
COM-001-1.1	R3.	Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide a means to coordinate telecommunications among their respective areas. This coordination shall include the ability to investigate and recommend solutions to telecommunications problems within the area and with other areas.				TOP	
COM-001-1.1	R4.	Unless agreed to otherwise, each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected Bulk Electric System. Transmission Operators and				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		Balancing Authorities may use an alternate language for internal operations.					
COM-001-1.1	R5.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have written operating instructions and procedures to enable continued operation of the system during the loss of telecommunications facilities.				TOP	
COM-002-2	R1.	Each Transmission Operator, Balancing Authority, and Generator Operator shall have communications (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators. Such communications shall be staffed and available for addressing a real-time emergency condition.		GOP		TOP	
COM-002-2	R1.1.	Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators through predetermined communication paths of any condition that could threaten the reliability of its area or when firm load shedding is anticipated.				TOP	
COM-002-2	R2.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall ensure the recipient of the directive repeats the information back correctly; and shall acknowledge the response as correct or repeat the original statement to resolve any misunderstandings.				TOP	
EOP-001-0	R2.	The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.					
EOP-001-0	R3.	Each Transmission Operator and Balancing Authority shall:				TOP	
EOP-001-0	R3.1.	Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.				TOP	
EOP-001-0	R3.2.	Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.				TOP	
EOP-001-0	R3.3.	Develop, maintain, and implement a set of plans for load shedding.				TOP	
EOP-001-0	R3.4.	Develop, maintain, and implement a set of plans for system restoration.				TOP	
EOP-001-0	R4.	Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:				TOP	
EOP-001-0	R4.1.	Communications protocols to be used during emergencies.				TOP	
EOP-001-0	R4.2.	A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.				TOP	
EOP-001-0	R4.3.	The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.				TOP	
EOP-001-0	R4.4.	Staffing levels for the emergency.				TOP	
EOP-001-0	R5.	Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-0 when developing an emergency plan.				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
EOP-001-0	R6.	The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.				TOP	
EOP-001-0	R7.	The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:				TOP	
EOP-001-0	R7.1.	The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.				TOP	
EOP-001-0	R7.2.	The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.				TOP	
EOP-001-0	R7.3.	The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules, including outages to the Generator Interconnection Facility, to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)				TOP	
EOP-001-0	R7.4.	The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.				TOP	
EOP-003-1	R1.	After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		failure of components or cascading outages of the Interconnection.					
EOP-003-1	R2.	Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions.				TOP	
EOP-003-1	R3.	Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected Transmission Operators and Balancing Authorities.				TOP	
EOP-003-1	R4.	A Transmission Operator or Balancing Authority shall consider one or more of these factors in designing an automatic load shedding scheme: frequency, rate of frequency decay, voltage level, rate of voltage decay, or power flow levels.				TOP	
EOP-003-1	R5.	A Transmission Operator or Balancing Authority shall implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.				TOP	
EOP-003-1	R6.	After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.				TOP	
EOP-003-1	R7.	The Transmission Operator, Generator Operator, and Balancing Authority shall coordinate automatic load shedding throughout their areas with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions.				TOP	Generic issue: -Need to add Generator Operator applicability to ensure the units' frequency trip set points are appropriately included in the needed coordination. This change is required only if the PRC-024-1 standard under development now as part of the Generator Verification drafting team does not

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
							adequately address the issue.
EOP-003-1	R8.	Each Transmission Operator or Balancing Authority shall have plans for operator-controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.				TOP	
EOP-004-1	R2.	A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity shall promptly analyze Bulk Electric System disturbances on its system or facilities, including those for the Generator Interconnection Facility.		GOP		TOP	
EOP-004-1	R3.	A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity experiencing a reportable incident shall provide a preliminary written report to its Regional Reliability Organization and NERC.		GOP		TOP	
EOP-004-1	R3.1.	The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load-Serving Entity shall submit within 24 hours of the disturbance or unusual occurrence either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report form. Events that are not identified until some time after they occur shall be reported within 24 hours of being recognized.		GOP		TOP	
EOP-004-1	R3.2.	Applicable reporting forms are provided in Attachments 022-1 and 022-2.		GOP		TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
EOP-004-1	R3.3.	Under certain adverse conditions, e.g., severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Interconnection Reliability Operating Limit and Preliminary Disturbance Report within 24 hours. In such cases, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity shall promptly notify its Regional Reliability Organization(s) and NERC, and verbally provide as much information as is available at that time. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.		GOP		TOP	
EOP-004-1	R3.4.	If, in the judgment of the Regional Reliability Organization, after consultation with the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity in which a disturbance occurred, a final report is required, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load-Serving Entity shall prepare this report within 60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent recurrence of this type of event. The report shall be subject to Regional Reliability Organization approval.		GOP		TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
EOP-005-1	R1.	Each Transmission Operator shall have a restoration plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system, including necessary operating instructions and procedures to cover emergency conditions, and the loss of vital telecommunications channels. Each Transmission Operator shall include the applicable elements listed in Attachment 1-EOP-005 in developing a restoration plan.				TOP	
EOP-005-1	R2.	Each Transmission Operator shall review and update its restoration plan at least annually and whenever it makes changes in the power system network, and shall correct deficiencies found during the simulated restoration exercises.				TOP	
EOP-005-1	R3.	Each Transmission Operator shall develop restoration plans with a priority of restoring the integrity of the Interconnection.				TOP	
EOP-005-1	R4.	Each Transmission Operator shall coordinate its restoration plans with the Generator Owners and Balancing Authorities within its area, its Reliability Coordinator, and neighboring Transmission Operators and Balancing Authorities.				TOP	
EOP-005-1	R5.	Each Transmission Operator and Balancing Authority shall periodically test its telecommunication facilities needed to implement the restoration plan.				TOP	
EOP-005-1	R6.	Each Transmission Operator and Balancing Authority shall train its operating personnel in the implementation of the restoration plan. Such training shall include simulated exercises, if practicable.				TOP	
EOP-005-1	R7.	Each Transmission Operator and Balancing Authority shall verify the restoration procedure by actual testing or by simulation.				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
EOP-005-1	R8.	Each Transmission Operator shall verify that the number, size, availability, and location of system blackstart generating units are sufficient to meet Regional Reliability Organization restoration plan requirements for the Transmission Operator's area.				TOP	
EOP-005-1	R9.	The Transmission Operator shall document the Cranking Paths, including initial switching requirements, between each blackstart generating unit and the unit(s) to be started and shall provide this documentation for review by the Regional Reliability Organization upon request. Such documentation may include Cranking Path diagrams.				TOP	
EOP-005-1	R10.	The Transmission Operator shall demonstrate, through simulation or testing, that the blackstart generating units in its restoration plan can perform their intended functions as required in the regional restoration plan.				TOP	
EOP-005-1	R10.1.	The Transmission Operator shall perform this simulation or testing at least once every five years.				TOP	
EOP-005-1	R11.	Following a disturbance in which one or more areas of the Bulk Electric System become isolated or blacked out, the affected Transmission Operators and Balancing Authorities shall begin immediately to return the Bulk Electric System to normal.				TOP	
EOP-005-1	R11.1.	The affected Transmission Operators and Balancing Authorities shall work in conjunction with their Reliability Coordinator(s) to determine the extent and condition of the isolated area(s).				TOP	
EOP-005-1	R11.2.	The affected Transmission Operators and Balancing Authorities shall take the necessary actions to restore Bulk Electric System frequency to normal, including adjusting generation, placing additional generators on line, or load shedding.				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
EOP-005-1	R11.4.	The affected Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.				TOP	
EOP-005-1	R11.5.	The affected Transmission Operators may resynchronize the isolated area(s) with the surrounding area(s) when the following conditions are met:				TOP	The team identified this as a potential general issue. However, when one considers the new requirements recommended (found in TOP-001 R7 Comment area), the TOP has decision-making authority over the Generator Interconnection Operational Interface, there is no gap created through this specific requirement.
EOP-005-1	R11.5.1.	Voltage, frequency, and phase angle permit.				TOP	
EOP-005-1	R11.5.2.	The size of the area being reconnected and the capacity of the transmission lines effecting the reconnection and the number of synchronizing points across the system are considered.				TOP	
EOP-005-1	R11.5.3.	Reliability Coordinator(s) and adjacent areas are notified and Reliability Coordinator approval is given.				TOP	
EOP-005-1	R11.5.4.	Load is shed in neighboring areas, if required, to permit successful interconnected system restoration.				TOP	
EOP-008-0	R1.	Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have a plan to continue reliability operations in the event its control center becomes inoperable. The contingency plan must meet the following requirements:				TOP	
EOP-008-0	R1.1.	The contingency plan shall not rely on data or voice communication from the primary control facility to be viable.				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
EOP-008-0	R1.2.	The plan shall include procedures and responsibilities for providing basic tie line control and procedures and for maintaining the status of all inter-area schedules, such that there is an hourly accounting of all schedules.				TOP	
EOP-008-0	R1.3.	The contingency plan must address monitoring and control of critical transmission facilities, Generator Interconnection Operational Interface, generation control, voltage control, time and frequency control, control of critical substation devices, and logging of significant power system events. The plan shall list the critical facilities.				TOP	
EOP-008-0	R1.4.	The plan shall include procedures and responsibilities for maintaining basic voice communication capabilities with other areas.				TOP	
EOP-008-0	R1.5.	The plan shall include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan.				TOP	
EOP-008-0	R1.6.	The plan shall include procedures and responsibilities for providing annual training to ensure that operating personnel are able to implement the contingency plans.				TOP	
EOP-008-0	R1.7.	The plan shall be reviewed and updated annually.				TOP	
EOP-008-0	R1.8.	Interim provisions must be included if it is expected to take more than one hour to implement the contingency plan for loss of primary control facility.				TOP	
EOP-009-0	R1.	The Generator Operator of each blackstart generating unit shall test the startup and operation of each system blackstart generating unit identified in the BCP as required in the Regional BCP (Reliability Standard EOP-007-0_R1). Testing records shall include the dates of the tests, the duration of the tests, and an indication of whether the tests met Regional BCP		GOP			

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		requirements.					
EOP-009-0	R2.	The Generator Owner or Generator Operator shall provide documentation of the test results of the startup and operation of each blackstart generating unit to the Regional Reliability Organizations and upon request to NERC.	GO	GOP			
FAC-001-0	R1.	The Transmission Owner shall document, maintain, and publish facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Reliability Organization, subregional, Power Pool, and individual Transmission Owner planning criteria and facility connection requirements. The Transmission Owner's facility connection requirements shall address connection requirements for:			TO		
FAC-001-0	R1.1.	Generation facilities, including the Generator Interconnection Facility,			TO		
FAC-001-0	R1.2.	Transmission facilities, and			TO		
FAC-001-0	R1.3.	End-user facilities			TO		
FAC-001-0	R2.	The Transmission Owner's facility connection requirements shall address, but are not limited to, the following items:			TO		
FAC-001-0	R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:			TO		
FAC-001-0	R2.1.1.	Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.			TO		
FAC-001-0	R2.1.2.	Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as soon as feasible.			TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
FAC-001-0	R2.1.3.	Voltage level and MW and MVAR capacity or demand at point of connection.			TO		
FAC-001-0	R2.1.4.	Breaker duty and surge protection.			TO		
FAC-001-0	R2.1.5.	System protection and coordination.			TO		
FAC-001-0	R2.1.6.	Metering and telecommunications.			TO		
FAC-001-0	R2.1.7.	Grounding and safety issues.			TO		
FAC-001-0	R2.1.8.	Insulation and insulation coordination.			TO		
FAC-001-0	R2.1.9.	Voltage, Reactive Power, and power factor control.			TO		
FAC-001-0	R2.1.10.	Power quality impacts.			TO		
FAC-001-0	R2.1.11.	Equipment Ratings.			TO		
FAC-001-0	R2.1.12.	Synchronizing of facilities.			TO		
FAC-001-0	R2.1.13.	Maintenance coordination.			TO		
FAC-001-0	R2.1.14.	Operational issues (abnormal frequency and voltages).			TO		
FAC-001-0	R2.1.15.	Inspection requirements for existing or new facilities.			TO		
FAC-001-0	R2.1.16.	Communications and procedures during normal and emergency operating conditions.			TO		
FAC-001-0	R3.	The Transmission Owner shall maintain and update its facility connection requirements as required. The Transmission Owner shall make documentation of these requirements available to the users of the transmission system, the Regional Reliability Organization, and NERC on request (five business days).			TO		
FAC-002-0	R1.	The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include:	GO		TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
FAC-002-0	R1.1.	Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.	GO		TO		
FAC-002-0	R1.2.	Ensurance of compliance with NERC Reliability Standards and applicable Regional, subregional, Power Pool, and individual system planning criteria and facility connection requirements.	GO		TO		
FAC-002-0	R1.3.	Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved.	GO		TO		
FAC-002-0	R1.4.	Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance in accordance with Reliability Standard TPL-001-0.	GO		TO		
FAC-002-0	R1.5.	Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.	GO		TO		
FAC-002-0	R2.	The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems) for three years and shall provide the documentation to the Regional Reliability Organization(s) Regional Reliability Organization(s) and NERC on request (within 30 calendar days).	GO		TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
FAC-003-1	R1.	The Transmission owner and Generator Owner shall prepare, and keep current, a formal transmission vegetation management (TVM). The TVMP shall include the Transmission Owner's and Generator Owner's objectives, practices, approved procedures, and work Specifications. 1. ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.			TO		Applies to the Generator Interconnection Facility above 200 kV that exceeds two spans from the generator property line or are otherwise deemed critical by the Regional Entity below 200 kV (subject to the two-span criteria.)
FAC-003-1	R1.1.	The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's or Generator Owner's transmission lines.			TO		
FAC-003-1	R1.2.	The Transmission Owner and Generator Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner and Generator Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead			TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		ungrounded supply conductors.					
FAC-003-1	R1.2.1.	Clearance 1 — The Transmission Owner and Generator Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner or Generator Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.			TO		
FAC-003-1	R1.2.2.	Clearance 2 — The Transmission Owner and Generator Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific and Generator Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in			TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		the Air Gap.					
FAC-003-1	R1.2.2.1.	Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.			TO		
FAC-003-1	R1.2.2.2.	Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.			TO		
FAC-003-1	R1.3.	All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner or Generator Owner, to perform their duties.			TO		
FAC-003-1	R1.4.	Each Transmission Owner and Generator Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner or Generator Owner is restricted from attaining the clearances specified in Requirement 1.2.1.			TO		
FAC-003-1	R1.5.	Each Transmission Owner and Generator Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.			TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
FAC-003-1	R2.	The Transmission Owner and Generator Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner and Generator Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.			TO		
FAC-003-1	R3.	The Transmission Owner and Generator Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner or Generator Owner to have been caused by vegetation.			TO		
FAC-003-1	R3.1.	Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period.			TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
FAC-003-1	R3.2.	The Transmission Owner or Generator Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner, Generator Owner, or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).			TO		
FAC-003-1	R3.3.	The outage information provided by the Transmission Owner or Generator Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner or Generator Owner.			TO		
FAC-003-1	R3.4.	An outage shall be categorized as one of the following:			TO		
FAC-003-1	R3.4.1.	Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;			TO		
FAC-003-1	R3.4.2.	Category 2 — Fall-ins: Outages caused by vegetation			TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		falling into lines from inside the ROW;					
FAC-003-1	R3.4.3.	Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.			TO		
FAC-008-1	R1.	The Transmission Owner and Generator Owner shall each document its current methodology used for developing Facility Ratings (Facility Ratings Methodology) of its solely and jointly owned Facilities, including the Generator Interconnection Facility. The methodology shall include all of the following:	GO		TO		
FAC-008-1	R1.1.	A statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.	GO		TO		
FAC-008-1	R1.2.	The method by which the Rating (of major BES equipment that comprises a Facility) is determined.	GO		TO		
FAC-008-1	R1.2.1.	The scope of equipment addressed shall include, but not be limited to, generators, the Generator Interconnection Facility, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.	GO		TO		
FAC-008-1	R1.2.2.	The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.	GO		TO		
FAC-008-1	R1.3.	Consideration of the following:	GO		TO		
FAC-008-1	R1.3.1.	Ratings provided by equipment manufacturers.	GO		TO		
FAC-008-1	R1.3.2.	Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer's warranty, IEEE, ANSI or other standards).	GO		TO		
FAC-008-1	R1.3.3.	Ambient conditions.	GO		TO		
FAC-008-1	R1.3.4.	Operating limitations.	GO		TO		
FAC-008-1	R1.3.5.	Other assumptions.	GO		TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
FAC-008-1	R2.	The Transmission Owner and Generator Owner shall each make its Facility Ratings Methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated Facilities are located, within 15 business days of receipt of a request.	GO		TO		
FAC-008-1	R3.	If a Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides written comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall provide a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.	GO		TO		
FAC-009-1	R1.	The Transmission Owner and Generator Owner shall each establish Facility Ratings for its solely and jointly owned Facilities, including the Generator Interconnection Facility, that are consistent with the associated Facility Ratings Methodology.	GO		TO		
FAC-009-1	R2.	The Transmission Owner and Generator Owner shall each provide Facility Ratings for its solely and jointly owned Facilities, including the Generator Interconnection Facility, that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.	GO		TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
FAC-014-1	R2.	The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.				TOP	
FAC-014-1	R5.2.	The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.				TOP	
INT-004-2	R2.3.	A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons.				TOP	
IRO-001-1.1	R8.	Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.		GOP		TOP	
IRO-002-1	R3.	Each Reliability Coordinator – or its Transmission Operators and Balancing Authorities – shall provide, or arrange provisions for, data exchange to other Reliability Coordinators or Transmission Operators and Balancing Authorities via a secure network.				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
IRO-004-1	R3.	Each Reliability Coordinator shall, in conjunction with its Transmission Operators and Balancing Authorities, develop action plans that may be required, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange Transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs.				TOP	
IRO-004-1	R4.	Each Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator, and Load-Serving Entity in the Reliability Coordinator Area shall provide information required for system studies, such as critical facility status, Load, generation, operating reserve projections, and known Interchange Transactions. This information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.	GO	GOP	TO	TOP	
IRO-004-1	R7.	Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.				TOP	The team considered whether an existing GOP-specific requirement existed to close what could have been a gap in coverage. The team concluded that IRO-001-1 R8 addresses this issue. Therefore, no gap exists.

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
IRO-005-2	R3.	As portions of the transmission system approach or exceed SOLs or IROLs, the Reliability Coordinator shall work with its Transmission Operators and Balancing Authorities to evaluate and assess any additional Interchange Schedules that would violate those limits. If a potential or actual IROL violation cannot be avoided through proactive intervention, the Reliability Coordinator shall initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall ensure all resources, including load shedding, are available to address a potential or actual IROL violation.				TOP	
IRO-005-2	R6.	Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.				TOP	
IRO-005-2	R8.	Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.				TOP	
IRO-005-2	R9.	The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages, including the		GOP		TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		Generator Interconnection Facility, with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.					
IRO-005-2	R12.	Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.				TOP	General issue with generators: For generating units that participate in some fashion in a Special Protection System or Remedial Action System that has supporting relaying or control equipment to enable this functionality, the GOP must notify the TOP of a status or condition change of the equipment. Therefore, a new requirement specific to the GOP must be added: Rx. The Generator Operator shall immediately inform the Transmission Operator of the status of the Special Protection System, including any degradation or potential failure to operate as expected for SPS relay or control equipment under its control.

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
IRO-005-2	R13.	Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.		GOP		TOP	
IRO-005-2	R15.	Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.				TOP	
IRO-005-2	R17.	When an IROL or SOL is exceeded, the Reliability Coordinator shall evaluate the local and wide-area impacts, both real-time and post-contingency, and determine if the actions being taken are appropriate and sufficient to return the system to within IROL in thirty minutes. If the actions being taken are not		GOP		TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		appropriate or sufficient, the Reliability Coordinator shall direct the Transmission Operator, Balancing Authority, Generator Operator, or Load-Serving Entity to return the system to within IROL or SOL.					
MOD-010-0	R1.	The Transmission Owners, Transmission Planners, Generator Owners (for plant and the Generator Interconnection Facility), and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R 1.	GO		TO		
MOD-010-0	R2.	The Transmission Owners, Transmission Planners, Generator Owners (for plant and the Generator Interconnection Facility), and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide this steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R 1. If no schedule exists, then these entities shall provide the data on request (30 calendar days).	GO		TO		
MOD-012-0	R1.	The Transmission Owners, Transmission Planners, Generator Owners (for plant and the Generator Interconnection Facility), and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and	GO		TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R1.					
MOD-012-0	R2.	The Transmission Owners, Transmission Planners, Generator Owners (for plant and the Generator Interconnection Facility), and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R4) shall provide dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R 1. If no schedule exists, then these entities shall provide data on request (30 calendar days).	GO		TO		
NUC-001-1	R1.	The Nuclear Plant Generator Operator shall provide the proposed NPIRs in writing to the applicable Transmission Entities and shall verify receipt	GO	GOP	TO	TOP	
NUC-001-1	R2.	The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements1 that include mutually agreed to NPIRs and document how the Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs.	GO	GOP	TO	TOP	
NUC-001-1	R3.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator.	GO	GOP	TO	TOP	
NUC-001-1	R4.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall:	GO	GOP	TO	TOP	
NUC-001-1	R4.1.	Incorporate the NPIRs into their operating analyses of	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		the electric system.					
NUC-001-1	R4.2.	Operate the electric system to meet the NPIRs.	GO	GOP	TO	TOP	
NUC-001-1	R4.3.	Inform the Nuclear Plant Generator Operator when the ability to assess the operation of the electric system affecting NPIRs is lost.	GO	GOP	TO	TOP	
NUC-001-1	R5.	The Nuclear Plant Generator Operator shall operate per the Agreements developed in accordance with this standard.		GOP			
NUC-001-1	R6.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities and the Nuclear Plant Generator Operator shall coordinate outages and maintenance activities which affect the NPIRs.	GO	GOP	TO	TOP	
NUC-001-1	R7.	Per the Agreements developed in accordance with this standard, the Nuclear Plant Generator Operator shall inform the applicable Transmission Entities of actual or proposed changes to nuclear plant design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.	GO	GOP	TO	TOP	
NUC-001-1	R8.	Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs.	GO	GOP	TO	TOP	
NUC-001-1	R9.	The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include, as a minimum, the following elements within the agreement(s) identified in R2:	GO	GOP	TO	TOP	
NUC-001-1	R9.1.	Administrative elements:	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
NUC-001-1	R9.1.1.	Definitions of key terms used in the agreement.	GO	GOP	TO	TOP	
NUC-001-1	R9.1.2.	Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs.	GO	GOP	TO	TOP	
NUC-001-1	R9.1.3.	A requirement to review the agreement(s) at least every three years.	GO	GOP	TO	TOP	
NUC-001-1	R9.1.4.	A dispute resolution mechanism.	GO	GOP	TO	TOP	
NUC-001-1	R9.2.	Technical requirements and analysis:	GO	GOP	TO	TOP	
NUC-001-1	R9.2.1.	Identification of parameters, limits, configurations, and operating scenarios included in the NPIRs and, as applicable, procedures for providing any specific data not provided within the agreement.	GO	GOP	TO	TOP	
NUC-001-1	R9.2.2.	Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.	GO	GOP	TO	TOP	
NUC-001-1	R9.2.3.	Types of planning and operational analyses performed specifically to support the NPIRs, including the frequency of studies and types of Contingencies and scenarios required.	GO	GOP	TO	TOP	
NUC-001-1	R9.3.	Operations and maintenance coordination:	GO	GOP	TO	TOP	
NUC-001-1	R9.3.1.	Designation of ownership of electrical facilities at the interface between the electric system and the nuclear plant and responsibilities for operational control coordination and maintenance of these facilities.	GO	GOP	TO	TOP	
NUC-001-1	R9.3.2.	Identification of any maintenance requirements for equipment not owned or controlled by the Nuclear Plant Generator Operator that are necessary to meet the NPIRs.	GO	GOP	TO	TOP	
NUC-001-1	R9.3.3.	Coordination of testing, calibration and maintenance of on-site and off-site power supply systems and related components.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
NUC-001-1	R9.3.4.	Provisions to address mitigating actions needed to avoid violating NPIRs and to address periods when responsible Transmission Entity loses the ability to assess the capability of the electric system to meet the NPIRs. These provisions shall include responsibility to notify the Nuclear Plant Generator Operator within a specified time frame.	GO	GOP	TO	TOP	
NUC-001-1	R9.3.5.	Provision to consider nuclear plant coping times required by the NPIRs and their relation to the coordination of grid and nuclear plant restoration following a nuclear plant loss of Off-site Power.	GO	GOP	TO	TOP	
NUC-001-1	R9.3.6.	Coordination of physical and cyber security protection of the Bulk Electric System at the nuclear plant interface to ensure each asset is covered under at least one entity’s plan.	GO	GOP	TO	TOP	
NUC-001-1	R9.3.7.	Coordination of the NPIRs with transmission system Special Protection Systems and underfrequency and undervoltage load shedding programs.	GO	GOP	TO	TOP	
NUC-001-1	R9.4.	Communications and training:	GO	GOP	TO	TOP	
NUC-001-1	R9.4.1.	Provisions for communications between the Nuclear Plant Generator Operator and Transmission Entities, including communications protocols, notification time requirements, and definitions of terms.	GO	GOP	TO	TOP	
NUC-001-1	R9.4.2.	Provisions for coordination during an off-normal or emergency event affecting the NPIRs, including the need to provide timely information explaining the event, an estimate of when the system will be returned to a normal state, and the actual time the system is returned to normal.	GO	GOP	TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
NUC-001-1	R9.4.3.	Provisions for coordinating investigations of causes of unplanned events affecting the NPIRs and developing solutions to minimize future risk of such events.	GO	GOP	TO	TOP	
NUC-001-1	R9.4.4.	Provisions for supplying information necessary to report to government agencies, as related to NPIRs.	GO	GOP	TO	TOP	
NUC-001-1	R9.4.5.	Provisions for personnel training, as related to NPIRs.	GO	GOP	TO	TOP	
PER-001-0	R1.	Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.				TOP	Add R2 to PER-001-0 as follows: R2. Each Generator Operator shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and Generation Interconnection Facility, and the responsibility and authority to follow the directives of reliability authorities including the Transmission Operator and Balancing Authority.
PER-002-0	R1.	Each Transmission Operator, Generator Operator, and Balancing Authority shall be staffed with adequately trained operating personnel.				TOP	
PER-002-0	R2.	Each Transmission Operator and Balancing Authority shall have a training program for all operating personnel that are in:				TOP	To ensure complete coverage for the training of personnel with responsibility for operating the Generator Interconnection Facilities, a new requirement is needed: Add R3 as follows:

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
							R3. Each Generator Operator shall implement an initial and continuing training program for all operating personnel that are responsible for operating the Generator Interconnection Facility that verifies the personnel's ability and understanding to operate the equipment in a reliable manner.
PER-002-0	R2.1.	Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.				TOP	
PER-002-0	R2.2.	Positions directly responsible for complying with NERC standards.				TOP	
PER-002-0	R3.	For personnel identified in Requirement R2, the Transmission Operator and Balancing Authority shall provide a training program meeting the following criteria:				TOP	
PER-002-0	R3.1.	A set of training program objectives must be defined, based on NERC and Regional Reliability Organization standards, entity operating procedures, and applicable regulatory requirements. These objectives shall reference the knowledge and competencies needed to apply those standards, procedures, and requirements to normal, emergency, and restoration conditions for the Transmission Operator and Balancing Authority operating positions.				TOP	
PER-002-0	R3.2.	The training program must include a plan for the initial and continuing training of Transmission Operator and Balancing Authority operating personnel. That plan shall address knowledge and competencies required for reliable system operations.				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
PER-002-0	R3.3.	The training program must include training time for all Transmission Operator and Balancing Authority operating personnel to ensure their operating proficiency.				TOP	
PER-002-0	R3.4.	Training staff must be identified, and the staff must be competent in both knowledge of system operations and instructional capabilities.				TOP	
PER-002-0	R4.	For personnel identified in Requirement R2, each Transmission Operator and Balancing Authority shall provide its operating personnel at least five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.				TOP	
PER-003-0	R1.	Each Transmission Operator, Balancing Authority, and Reliability Coordinator shall staff all operating positions that meet both of the following criteria with personnel that are NERC-certified for the applicable functions:				TOP	
PER-003-0	R1.1.	Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.				TOP	
PER-003-0	R1.2.	Positions directly responsible for complying with NERC standards.				TOP	
PRC-001-1	R1.	Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area, including those for the Generator Interconnection Facility.		GOP		TOP	
PRC-001-1	R2.	Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures, including those for the Generator Interconnection Facility, as follows:		GOP		TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
PRC-001-1	R2.1.	If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.		GOP			
PRC-001-1	R2.2.	If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.				TOP	
PRC-001-1	R3.	A Generator Operator or Transmission Operator shall coordinate new protective systems and changes, including those for the Generator Interconnection Facility, as follows.		GOP		TOP	
PRC-001-1	R3.1.	Each Generator Operator shall coordinate all new protective systems and all protective system changes, including those for the Generator Interconnection Facility, with its Transmission Operator and Host Balancing Authority.		GOP			
PRC-001-1	R3.2.	Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.				TOP	
PRC-001-1	R4.	Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.				TOP	
PRC-001-1	R5.	A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions, including those for the Generator Interconnection Facility, that could require		GOP		TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		changes in the protection systems of others:					
PRC-001-1	R5.1.	Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions, including those for the Generator Interconnection Facility, that could require changes in the Transmission Operator's protection systems.		GOP			
PRC-001-1	R5.2.	Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.				TOP	
PRC-001-1	R6.	Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.				TOP	
PRC-004-1	R1.	The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1.			TO		
PRC-004-1	R2.	The Generator Owner shall analyze its generator Protection System Misoperations, including those for the Generator Interconnection Facility, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.	GO				

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
PRC-004-1	R3.	The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.	GO		TO		
PRC-005-1	R1.	Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System, including those for the Generator Interconnection Facility, shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:	GO		TO		
PRC-005-1	R1.1.	Maintenance and testing intervals and their basis.	GO		TO		
PRC-005-1	R1.2.	Summary of maintenance and testing procedures.	GO		TO		
PRC-005-1	R2.	Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System, including those for the Generator Interconnection Facility, shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:	GO		TO		
PRC-005-1	R2.1.	Evidence Protection System devices were maintained and tested within the defined intervals.	GO		TO		
PRC-005-1	R2.2.	Date each Protection System device was last tested/maintained.	GO		TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
PRC-007-0	R1.	The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall ensure that its UFLS program is consistent with its Regional Reliability Organization's UFLS program requirements.			TO		
PRC-007-0	R2.	The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide, and annually update, its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLSprogram database.			TO	TOP	
PRC-007-0	R3.	The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its documentation of that UFLS program to its Regional Reliability Organization on request (30 calendar days).			TO		
PRC-008-0	R1.	The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.			TO		
PRC-008-0	R2.	The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to its Regional Reliability Organization and NERC on request (within 30 calendar days).			TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
PRC-009-0	R1.	The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall analyze and document its UFLS program performance in accordance with its Regional Reliability Organization's UFLS program. The analysis shall address the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to:			TO	TOP	
PRC-009-0	R1.1.	A description of the event including initiating conditions.			TO	TOP	
PRC-009-0	R1.2.	A review of the UFLS set points and tripping times.			TO	TOP	
PRC-009-0	R1.3.	A simulation of the event.			TO	TOP	
PRC-009-0	R1.4.	A summary of the findings.			TO	TOP	
PRC-009-0	R2.	The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide documentation of the analysis of the UFLS program to its Regional Reliability Organization and NERC on request 90 calendar days after the system event.			TO	TOP	
PRC-010-0	R1.	The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall periodically (at least every five years or as required by changes in system conditions) conduct and document an assessment of the effectiveness of the UVLS program. This assessment shall be conducted with the associated Transmission Planner(s) and Planning			TO	TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		Authority(ies).					
PRC-010-0	R1.1.	This assessment shall include, but is not limited to:			TO	TOP	
PRC-010-0	R1.1.1.	Coordination of the UVLS programs with other protection and control systems in the Region and with other Regional Reliability Organizations, as appropriate.			TO	TOP	
PRC-010-0	R1.1.2.	Simulations that demonstrate that the UVLS programs performance is consistent with Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0.			TO	TOP	
PRC-010-0	R1.1.3.	A review of the voltage set points and timing.			TO	TOP	
PRC-010-0	R2.	The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall provide documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC on request (30 calendar days).			TO	TOP	
PRC-011-0	R1.	The Transmission Owner and Distribution Provider that owns a UVLS system shall have a UVLS equipment maintenance and testing program in place. This program shall include:			TO		
PRC-011-0	R1.1.	The UVLS system identification which shall include but is not limited to:			TO		
PRC-011-0	R1.1.1.	Relays.			TO		
PRC-011-0	R1.1.2.	Instrument transformers.			TO		
PRC-011-0	R1.1.3.	Communications systems, where appropriate.			TO		
PRC-011-0	R1.1.4.	Batteries.			TO		
PRC-011-0	R1.2.	Documentation of maintenance and testing intervals and their basis.			TO		
PRC-011-0	R1.3.	Summary of testing procedure.			TO		
PRC-011-0	R1.4.	Schedule for system testing.			TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
PRC-011-0	R1.5.	Schedule for system maintenance.			TO		
PRC-011-0	R1.6.	Date last tested/maintained.			TO		
PRC-011-0	R2.	The Transmission Owner and Distribution Provider that owns a UVLS system shall provide documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program to its Regional Reliability Organization and NERC on request (within 30 calendar days).			TO		
PRC-015-0	R1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list of and provide data for existing and proposed SPSs as specified in Reliability Standard PRC-013-0_R 1.	GO		TO		
PRC-015-0	R2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.	GO		TO		
PRC-015-0	R3.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).	GO		TO		
PRC-016-0.1	R1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall analyze its SPS operations and maintain a record of all misoperations in accordance with the Regional SPS	GO		TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		review procedure specified in Reliability Standard PRC-012-0_R1.					
PRC-016-0.1	R2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall take corrective actions to avoid future misoperations.	GO		TO		
PRC-016-0.1	R3.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).	GO		TO		
PRC-017-0	R1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place. The program(s) shall include:	GO		TO		
PRC-017-0	R1.1.	SPS identification shall include but is not limited to:	GO		TO		
PRC-017-0	R1.1.1.	Relays.	GO		TO		
PRC-017-0	R1.1.2.	Instrument transformers.	GO		TO		
PRC-017-0	R1.1.3.	Communications systems, where appropriate.	GO		TO		
PRC-017-0	R1.1.4.	Batteries.	GO		TO		
PRC-017-0	R1.2.	Documentation of maintenance and testing intervals and their basis.	GO		TO		
PRC-017-0	R1.3.	Summary of testing procedure.	GO		TO		
PRC-017-0	R1.4.	Schedule for system testing.	GO		TO		
PRC-017-0	R1.5.	Schedule for system maintenance.	GO		TO		
PRC-017-0	R1.6.	Date last tested/maintained.	GO		TO		
PRC-017-0	R2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).	GO		TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
PRC-018-1	R1.	Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements:	GO		TO		
PRC-018-1	R1.1.	Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC)	GO		TO		
PRC-018-1	R1.2.	Recorded data from each Disturbance shall be retrievable for ten calendar days.	GO		TO		
PRC-018-1	R2.	The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3).	GO		TO		
PRC-018-1	R3.	The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region's installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1):	GO		TO		
PRC-018-1	R3.1.	Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder).	GO		TO		
PRC-018-1	R3.2.	Make and model of equipment.	GO		TO		
PRC-018-1	R3.3.	Installation location.	GO		TO		
PRC-018-1	R3.4.	Operational status.	GO		TO		
PRC-018-1	R3.5.	Date last tested.	GO		TO		
PRC-018-1	R3.6.	Monitored elements, such as transmission circuit, bus section, etc.	GO		TO		
PRC-018-1	R3.7.	Monitored devices, such as circuit breaker, disconnect status, alarms, etc.	GO		TO		
PRC-018-1	R3.8.	Monitored electrical quantities, such as voltage,	GO		TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		current, etc.					
PRC-018-1	R4.	The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard PRC-002 Requirement 4).	GO		TO		
PRC-018-1	R5.	The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years.	GO		TO		
PRC-018-1	R6.	Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes:	GO		TO		
PRC-018-1	R6.1.	Maintenance and testing intervals and their basis.	GO		TO		
PRC-018-1	R6.2.	Summary of maintenance and testing procedures.	GO		TO		
PRC-021-1	R1.	Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall annually update its UVLS data to support the Regional UVLS program database. The following data shall be provided to the Regional Reliability Organization for each installed UVLS system:			TO		
PRC-021-1	R1.1.	Size and location of customer load, or percent of connected load, to be interrupted.			TO		
PRC-021-1	R1.2.	Corresponding voltage set points and overall scheme clearing times.			TO		
PRC-021-1	R1.3.	Time delay from initiation to trip signal.			TO		
PRC-021-1	R1.4.	Breaker operating times.			TO		

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
PRC-021-1	R1.5.	Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Special Protection Systems.			TO		
PRC-021-1	R2.	Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request.			TO		
PRC-022-1	R1.	Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall analyze and document all UVLS operations and Misoperations. The analysis shall include:				TOP	
PRC-022-1	R1.1.	A description of the event including initiating conditions.				TOP	
PRC-022-1	R1.2.	A review of the UVLS set points and tripping times.				TOP	
PRC-022-1	R1.3.	A simulation of the event, if deemed appropriate by the Regional Reliability Organization. For most events, analysis of sequence of events may be sufficient and dynamic simulations may not be needed.				TOP	
PRC-022-1	R1.4.	A summary of the findings.				TOP	
PRC-022-1	R1.5.	For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature.				TOP	
PRC-022-1	R2.	Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall provide documentation of its analysis of UVLS program performance to its Regional Reliability Organization within 90 calendar days of a request.				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
TOP-001-1	R1.	Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.				TOP	
TOP-001-1	R2.	Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.				TOP	Gap identified: covered by new requirement outlined in TOP-001-R7 Comment area.
TOP-001-1	R3.	Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority, or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.		GOP		TOP	
TOP-001-1	R5.	Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real-time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.				TOP	Gap identified: covered by new requirement outlined in TOP-001-R7 Comment area.

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
TOP-001-1	R6.	Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.		GOP		TOP	
TOP-001-1	R7.	Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities, including the Generator Interconnection Facility, from service if removing those facilities would burden neighboring systems unless:		GOP		TOP	Need to add new requirements to address interconnection facilities: Add R9 as follows: R9. The Generator Operator shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects in order to preserve Interconnection reliability with respect to the following: • Switching elements • Outage planning • Real-time or anticipated emergency conditions • Other conditions mutually agreed upon by the Generator Operator and Transmission Operator Add R10 as follows: R10. The Transmission Operator shall have decision-making authority over operation of the

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
							Generator Interconnection Operational Interface at all times in order to preserve Interconnection reliability.
TOP-001-1	R7.1.	For a generator outage, including the Generator Interconnection Facility, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.		GOP		TOP	
TOP-001-1	R7.2.	For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.				TOP	
TOP-001-1	R7.3.	When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.		GOP		TOP	
TOP-001-1	R8.	During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.					
TOP-002-2	R1.	Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.				TOP	
TOP-002-2	R2.	Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.				TOP	
TOP-002-2	R3.	Each Load-Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations, including for the Generator Interconnection Facility, with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.		GOP			
TOP-002-2	R4.	Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.					
TOP-002-2	R5.	Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.				TOP	
TOP-002-2	R6.	Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.				TOP	
TOP-002-2	R10.	Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).				TOP	
TOP-002-2	R11.	The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.				TOP	
TOP-002-2	R13.	At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel		GOP			

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.					
TOP-002-2	R14.	Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:		GOP			
TOP-002-2	R14.1.	Changes in real output capabilities.		GOP			
TOP-002-2	R14.2.	Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)		GOP			Add R14.3 as follows: Changes in Generator Interconnection Facility Status
TOP-002-2	R15.	Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).		GOP			
TOP-002-2	R16.	Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:				TOP	
TOP-002-2	R16.1.	Changes in transmission facility status.				TOP	
TOP-002-2	R16.2.	Changes in transmission facility rating.				TOP	
TOP-002-2	R17.	Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
TOP-002-2	R18.	Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers, and Load-Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network and for the Generator Interconnection Facility.		GOP		TOP	
TOP-002-2	R19.	Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.				TOP	
TOP-003-0	R1.	Generator Operators and Transmission Operators shall provide planned outage information, including information for the Generator Interconnection Facility.		GOP		TOP	
TOP-003-0	R1.1.	Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW) or for the Generator Interconnection Facility. The Transmission Operator shall establish the outage reporting requirements.		GOP		TOP	
TOP-003-0	R1.2.	Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements.				TOP	
TOP-003-0	R1.3.	Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		1200 Pacific Standard Time for the Western Interconnection.					
TOP-003-0	R2.	Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.		GOP		TOP	
TOP-003-0	R3.	Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.		GOP		TOP	
TOP-004-2	R1.	Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).				TOP	To close gap for GOP operation of its Generator Interconnection Facilities, a new requirement is needed: Add R7 as follows: Rx. The Generator Operator shall operate its Generator Interconnection Facility within its applicable ratings.
TOP-004-2	R2.	Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.				TOP	
TOP-004-2	R3.	Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		specified by its Reliability Coordinator.					
TOP-004-2	R4.	If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.				TOP	
TOP-004-2	R5.	Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.				TOP	
TOP-004-2	R6.	Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:				TOP	
TOP-004-2	R6.1.	Monitoring and controlling voltage levels and real and reactive power flows.				TOP	
TOP-004-2	R6.2.	Switching transmission elements.				TOP	
TOP-004-2	R6.3.	Planned outages of transmission elements.				TOP	
TOP-004-2	R6.4.	Responding to IROL and SOL violations.				TOP	
TOP-005-1.1	R1.	Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area.				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
TOP-005-1.1	R3.	Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.				TOP	
TOP-006-1	R1.	Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.				TOP	
TOP-006-1	R1.1.	Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.		GOP			
TOP-006-1	R1.2.	Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.				TOP	
TOP-006-1	R2.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.				TOP	
TOP-006-1	R3.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
		their operating personnel.					
TOP-006-1	R4.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.				TOP	
TOP-006-1	R5.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.				TOP	
TOP-006-1	R6.	Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.				TOP	
TOP-006-1	R7.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.				TOP	
TOP-007-0	R1.	A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.				TOP	
TOP-007-0	R2.	Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.				TOP	
TOP-007-0	R3.	A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R 2.				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
TOP-008-1	R1.	The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.				TOP	
TOP-008-1	R2.	Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.				TOP	
TOP-008-1	R3.	The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.				TOP	Add companion GOP requirement to ensure clarity: Add R5 as follows: R5. The Generator Operator shall disconnect the Generator Interconnection Facility when safety is jeopardized or the overload or abnormal voltage or reactive condition persists and generating equipment or the Generator Interconnection Facility is endangered. In doing so, the Generator Operator shall notify its Transmission Operator and Balancing Authority impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
TOP-008-1	R4.	The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.				TOP	
VAR-001-1	R1.	Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.				TOP	
VAR-001-1	R2.	Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.				TOP	
VAR-001-1	R3.	The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.				TOP	
VAR-001-1	R3.1.	Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.				TOP	
VAR-001-1	R3.2.	For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
VAR-001-1	R4.	Each Transmission Operator shall specify a voltage or Reactive Power schedule at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage).				TOP	
VAR-001-1	R6.	The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.				TOP	
VAR-001-1	R6.1.	When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.				TOP	
VAR-001-1	R7.	The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.				TOP	
VAR-001-1	R8.	Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line, Generator Interconnection Facility, and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.				TOP	
VAR-001-1	R9.	Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.				TOP	

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
VAR-001-1	R9.1.	Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.				TOP	
VAR-001-1	R10.	Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.				TOP	
VAR-001-1	R11.	After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.				TOP	
VAR-001-1	R12.	The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.				TOP	
VAR-002-1.1a	R1.	The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.		GOP			
VAR-002-1.1a	R2.	Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings. [1] as directed by the Transmission Operator		GOP			

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
VAR-002-1.1a	R2.1.	When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.		GOP			
VAR-002-1.1a	R2.2.	When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.		GOP			
VAR-002-1.1a	R3.	Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:		GOP			
VAR-002-1.1a	R3.1.	A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.		GOP			
VAR-002-1.1a	R3.2.	A status or capability change on any other Reactive Power resources under the Generator Operator's control, including the Generator Interconnection Facility, and the expected duration of the change in status or capability.		GOP			
VAR-002-1.1a	R4.	The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.	GO				
VAR-002-1.1a	R4.1.	For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:	GO				
VAR-002-1.1a	R4.1.1.	Tap settings.	GO				
VAR-002-1.1a	R4.1.2.	Available fixed tap ranges.	GO				
VAR-002-1.1a	R4.1.3.	Impedance data.	GO				

Standard Number	Requirement Number	Text of Requirement	GO	GOP	TO	TOP	Comments
VAR-002-1.1a	R4.1.4.	The +/- voltage range with step-change in % for load-tap changing transformers.	GO				
VAR-002-1.1a	R5.	After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.	GO				
VAR-002-1.1a	R5.1.	If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.		GOP			

Appendix 2 — Proposed Revisions to the Statement of Compliance Registry Criteria

Statement of Compliance Registry Criteria (Revision 6.0)

Summary

Since becoming the Electric Reliability Organization (ERO), NERC has initiated a program to identify candidate organizations for its compliance registry. The program, conducted by NERC and the Regional Entities[5], will also confirm the functions and information now on file for currently-registered organizations. NERC and the Regional Entities have the obligation to identify and register all entities that meet the criteria for inclusion in the compliance registry, as further explained in the balance of this document.

This document describes how NERC will identify organizations that may be candidates for registration and assign them to the compliance registry.

Organizations will be responsible to register and to comply with approved reliability standards to the extent that they are owners, operators, and users of the bulk power system, perform a function listed in the functional types identified in Section II of this document, and are material to the reliable operation of the interconnected bulk power system as defined by the criteria and notes set forth in this document. NERC will apply the following principles to the compliance registry:

- In order to carry out its responsibilities related to enforcement of Reliability Standards, NERC must identify the owners, operators, and users of the bulk power system who have a material impact[6] on the bulk power system through a compliance registry. NERC and the Regional Entities will make their best efforts to identify all owners, users and operators who have a material reliability impact on the bulk power system in order to develop a complete and current registry list. The registry will be updated as required and maintained on an on-going basis.
- Organizations listed in the compliance registry are responsible and will be monitored for compliance with applicable mandatory reliability standards. They will be subject to NERC's and the Regional Entities' compliance and enforcement programs.
- NERC and Regional Entities will not monitor nor hold those not in the registry responsible for compliance with the standards. An entity which is not initially placed on the registry, but which is identified subsequently as having a material reliability impact, will be added to the registry. Such entity will not be subject to a sanction or penalty by NERC or the Regional Entity for actions or inactions prior to being placed

[5] The term “Regional Entities” includes Cross-Border Regional Entities.
[6] The criteria for determining whether an entity will be placed on the registry are set forth in the balance of this document. At any time a person may recommend in writing, with supporting reasons, to the director of compliance that an organization be added to or removed from the compliance registry, pursuant to NERC ROP 501.1.3.5.

on the registry, but may be required to comply with a remedial action directive or mitigation plan in order to become compliant with applicable standards. After such entity has been placed on the compliance registry, it shall be responsible for

complying with Reliability Standards and may be subject to sanctions or penalties as well as any remedial action directives and mitigation plans required by the Regional Entities or NERC for future violations, including any failure to follow a remedial action directive or mitigation plan to become compliant with Reliability Standards.

- Required compliance by a given organization with the standards will begin the later of (i) inclusion of that organization in the compliance registry and (ii) approval by the appropriate governmental authority of mandatory reliability standards applicable to the entity.

Entities responsible for funding NERC and the Regional Entities have been identified in the budget documents filed with FERC. Presence on or absence from the compliance registry has no bearing on an entity's independent responsibility for funding NERC and the Regional Entities.

Background

In 2005, NERC and the Regional Entities conducted a voluntary organization registration program limited to balancing authorities, planning authorities, regional reliability organizations, reliability coordinators, transmission operators, and transmission planners. The list of the entities that were registered constitutes what NERC considered at that time as its compliance registry.

NERC has recently initiated a broader program to identify additional organizations potentially eligible to be included in the compliance registry and to confirm the information of organizations currently on file. NERC believes this is a prudent activity at this time because:

- As of July 20, 2006, NERC was certified as the ERO created for the U.S. by the Energy Policy Act of 2005 (EPAct) and FERC Order 672. NERC has also filed with Canadian authorities for similar recognition in their respective jurisdictions.
- FERC's Order 672 directs that owners, operators and users of the bulk power system shall be registered with the ERO and the appropriate Regional Entities.
- As the ERO, NERC has filed its current reliability standards with FERC and with Canadian authorities. As accepted and approved by FERC and appropriate Canadian authorities, the reliability standards are no longer voluntary, and organizations that do not fully comply with them may face penalties or other sanctions determined and levied by NERC or the Regional Entities.
- NERC's reliability standards include compliance requirements for additional reliability function types beyond the six types registered by earlier registration programs.
- Based on selection as the ERO, the extension and expansion of NERC's current registration program[7] is the means by which NERC and the Regional Entities will plan, manage and execute reliability standard compliance oversight of owners, operators, and users of the bulk power system.

[7] See: NERC ERO Application; Exhibit C; Section 500 – Organization Registration and Certification.

- Organizations listed in the compliance registry are subject to NERC's and the Regional Entities' compliance and enforcement programs.

Statement of Issue

As the ERO, NERC intends to comprehensively and thoroughly protect the reliability of the grid. To support this goal NERC will include in its compliance registry each entity that NERC concludes can materially impact the reliability of the bulk power system. However, the potential costs and effort of ensuring that every organization potentially within the scope of "owner, operator, and user of the bulk power system" becomes registered while ignoring their impact upon reliability, would be disproportionate to the improvement in reliability that would reasonably be anticipated from doing so.

NERC wishes to identify as many organizations as possible that may need to be listed in its compliance registry. Identifying these organizations is necessary and prudent at this time for the purpose of determining resource needs, both at the NERC and Regional Entity level, and to begin the process of communication with these entities regarding their potential responsibilities and obligations. NERC and the Regional Entities believe that primary candidate entities can be identified at this time, while other entities can be identified later, as and when needed. Selection principles and criteria for the identification of these initial entities are required. This list will become the "Initial Non-binding Organization Registration List". With FERC having made the approved Reliability Standards enforceable, this list becomes the NERC Compliance Registry.

Resolution

NERC and the Regional Entities have identified two principles they believe are key to the entity selection process. These are:

1. There needs to be consistency between regions and across the continent with respect to which entities are registered, and;
2. Any entity reasonably deemed material to the reliability of the bulk power system will be registered, irrespective of other considerations.

To address the second principle the Regional Entities, working with NERC, will identify and register any entity they deem material to the reliability of the bulk power system.

In order to promote consistency, NERC and the Regional Entities intend to use the following criteria as the basis for determining whether particular entities should be identified as candidates for registration. All organizations meeting or exceeding the criteria will be identified as candidates.

The following four groups of criteria (Sections I-IV) plus the statements in Section V will provide guidance regarding an entity's registration status:

- Section I determines if the entity is an owner, operator, or user of the bulk power system and, hence, a candidate for organization registration.

- Section II uses NERC's current functional type definitions to provide an initial determination of the functional types for which the entities identified in Section I should be considered for registration.
- Section III lists the criteria regarding smaller entities; these criteria can be used to forego the registration of entities that were selected to be considered for registration pursuant to Sections I and II and, if circumstances change, for later removing entities from the registration list that no longer meet the relevant criteria.
- Section IV — additional criteria for joint registration. Joint registration criteria may be used by Joint Action Agencies, Generation and Transmission Cooperatives and other entities which agree upon a clear division of compliance responsibility for Reliability Standards by written agreement. Pursuant to FERC's directive in paragraph 107 of Order No. 693, rules pertaining to joint registration and Joint Registration Organizations will now be found in Sections 501 and 507 of the NERC Rules of Procedure.

I. Entities that use, own or operate elements of the bulk electric system as established by NERC's approved definition of bulk electric system below are (i) owners, operators, and users of the bulk power system and (ii) candidates for registration:

> *"As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.[8]"*

II. Entities identified in Part I above will be categorized as registration candidates who may be subject to registration under one or more appropriate functional entity types based on a comparison of the functions the entity normally performs against the following function type definitions:

Function Type	**Acronym**	**Definition/Discussion**
Balancing Authority	BA	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a BA area, and supports Interconnection frequency in real-time.
Distribution Provider	DP	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the DP. Thus, the DP is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.

[8] However, ownership of radial transmission facilities intended to be covered by the vegetation management standard (applicable to transmission lines 200 kV and above) would be included in this definition.

Function Type	Acronym	Definition/Discussion
Generator Operator	GOP	The entity that operates generating unit(s) and the Generator Interconnection Facility and performs the functions of supplying energy and interconnected operations services.
Generator Owner	GO	Entity that owns and maintains generating units*, including its Generator Interconnection Facility*.
Interchange Authority	IA	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
Load-Serving Entity	LSE	Secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers.
Planning Authority	PA	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Purchasing-Selling Entity	PSE	The entity that purchases or sells and takes title to energy, capacity, and interconnected operations services. PSE may be affiliated or unaffiliated merchants and may or may not own generating facilities.
Reliability Coordinator	RC	The entity that is the highest level of authority who is responsible for the reliable operation of the bulk power system, has the wide area view of the bulk power system, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The RC has the purview that is broad enough to enable the calculation of interconnection reliability operating limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reserve Sharing Group	RSG	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each BA's use in recovering from contingencies within the group. Scheduling energy from an adjacent BA to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker, (e.g., between zero and ten minutes) then, for the purposes of disturbance control performance, the areas become a RSG.

Function Type	Acronym	Definition/Discussion
Resource Planner	RP	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a PA area.
Transmission Owner	TO	The entity that owns and maintains transmission facilities.
Transmission Operator	TOP	The entity responsible for the reliability of its local transmission system and operates or directs the operations of the transmission facilities.
Transmission Planner	TP	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the PA area.
Transmission Service Provider	TSP	The entity that administers the transmission tariff and provides transmission service to transmission customers under applicable transmission service agreements.

III. Entities identified in Part II above as being subject to registration as an LSE, DP, GO, GOP, TO, or TOP should be excluded from the registration list for these functions if they do not meet any of the criteria listed below:

III(a) Load-serving Entity:

Electrical load must be accounted for at the bulk power system level to properly plan and account for the load in the operation of the bulk power system. Load-serving entities will be registered regardless of whether they own or operate physical power system assets[9] as follows:

III.a.1 Load-serving entity owning and/or operating physical power system assets whose peak load is > 25 MW and load is otherwise unaccounted for by another registered Load-serving entity as described in the exclusion below, or;

III.a.2 Load-serving entity not owning and/or operating physical power system assets whose peak load is > 25 MW and load is otherwise unaccounted for by another registered Load-serving entity as described in the exclusion below, or;

III.a.3 Load-serving entity is designated as the responsible entity for facilities that are part of a required underfrequency load shedding (UFLS) program

[9] Entities not owning and/or operating physical power system assets that are responsible for serving retail end-use loads will not be required to comply with reliability standards related to asset ownership or operation.

designed, installed, and operated for the protection of the bulk power system, or;

III.a.4 Load-serving entity is designated as the responsible entity for facilities that are part of a required undervoltage load shedding (UVLS) program designed, installed, and operated for the protection of the bulk power system.

[Exclusion: A load-serving entity will not be registered based on these criteria if responsibilities for compliance with approved NERC reliability standards or associated requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a load-serving entity, balancing authority, transmission operator, G&T cooperative or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.]

III(b) Distribution Provider:

III.b.1 Distribution provider system serving >25 MW of peak load that is directly connected to the bulk power system.

[Exclusion: A distribution provider will not be registered based on this criterion if responsibilities for compliance with approved NERC reliability standards or associated requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a load-serving entity, balancing authority, transmission operator, G&T cooperative, or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.] or;

III.b.2 Distribution provider is the responsible entity that owns, controls, or operates facilities that are part of any of the following protection systems or programs designed, installed, and operated for the protection of the bulk power system:

- a required UFLS program.
- a required UVLS program.
- a required special protection system.
- a required transmission protection system.

[Exclusion: A distribution provider will not be registered based on these criteria if responsibilities for compliance with approved NERC reliability standards or associated requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a load-serving entity, balancing authority, transmission operator, G&T cooperative, or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.]

III(c) Generator Owner/Operator:

III.c.1 Individual generating unit > 20 MVA (gross nameplate rating) and is directly connected to the bulk power system, or;

III.c.2 Generating plant/facility > 75 MVA (gross aggregate nameplate rating) or when the entity has responsibility for any facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation above 75 MVA gross nameplate rating, or;

III.c.3 Any generator, regardless of size, that is a blackstart unit material to and designated as part of a transmission operator entity's restoration plan, or;

III.c.4 Any generator, regardless of size, that is material to the reliability of the bulk power system.

[Exclusions:

A generator owner/operator will not be registered based on these criteria if responsibilities for compliance with approved NERC reliability standards or associated requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a load-serving entity, G&T cooperative or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.

As a general matter, a customer-owned or operated generator/generation that serves all or part of retail load with electric energy on the customer's side of the retail meter may be excluded as a candidate for registration based on these criteria if (i) the net capacity provided to the bulk power system does not exceed the criteria above or the Regional Entity otherwise determines the generator is not material to the bulk power system and (ii) standby, back-up and maintenance power services are provided to the generator or to the retail load pursuant to a binding obligation with another generator owner/operator or under terms approved by the local regulatory authority or the Federal Energy Regulatory Commission, as applicable.

For purposes of applying these criteria, the Generator Interconnection Facility is considered as though part of the generating facility. The Generator Interconnection Facility is defined to be:

" Sole-use facility for the purpose of connecting the generating unit(s) to the transmission grid. In this regard, the sole-use facility only transmits power associated with the interconnecting generator, whether delivered to the grid or delivered to the generator for station service or auxiliary load, or delivered to meet cogeneration load requirements."]

III(d) Transmission Owner/Operator:

III.d.1 An entity that owns/operates an integrated transmission element associated with the bulk power system 100 kV and above, or lower voltage as defined by the Regional Entity necessary to provide for the reliable operation of the interconnected transmission grid; or

III.d.2 An entity that owns/operates a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity.

[Exclusion: A transmission owner/operator will not be registered based on these criteria if responsibilities for compliance with approved NERC reliability standards or associated requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, such as a load-serving entity, G&T cooperative or joint action agency as described in Sections 501 and 507 of the NERC Rules of Procedure.

In addition, a Generator Interconnection Facility as defined in Section III.c.4 is not considered an integrated transmission element for purposes of applying these criteria.]

IV. Joint Registration Organization and applicable Member Registration.

Pursuant to FERC's directive in paragraph 107 of Order No. 693, NERC's rules pertaining to joint registrations and Joint Registration Organizations are now found in Section 501 and 507 of the NERC Rules of Procedure.

V. If NERC or a Regional Entity encounters an organization that is not listed in the compliance registry, but which should be subject to the reliability standards, NERC or the Regional Entity is obligated and will add that organization to the registry, subject to that organization's right to challenge as provided in Section 500 of NERC's Rules of Procedure and as described in Note 3 below.

Notes to the above Criteria

1. The above are general criteria only. The Regional Entity considering registration of an organization not meeting (e.g., smaller in size than) the criteria may propose registration of that organization if the Regional Entity believes and can reasonably demonstrate[10] that the organization is a bulk power system owner, or operates, or uses bulk power system assets, and is material to the reliability of the bulk power system. Similarly, the Regional Entity may exclude an organization that meets the criteria described above as a candidate for registration if it believes and can reasonably demonstrate to NERC that the bulk power system owner, operator, or user does not have a material impact on the reliability of the bulk power system.

[10] The reasonableness of any such demonstration will be subject to review and remand by NERC itself, or by any agency having regulatory or statutory oversight of NERC as the ERO (e.g., FERC or appropriate Canadian authorities).

2. An organization not identified using the criteria, but wishing to be registered, may request that it be registered. For further information refer to: NERC Rules of Procedure, Section 500 – Organization Registration and Certification; Part 1.3.

3. An organization may challenge its registration within the compliance registry. NERC or the Regional Entity will provide the organization with all information necessary to timely challenge that determination including notice of the deadline for contesting the determination and the relevant procedures to be followed as described in the NERC Rules of Procedure; Section 500 – Organization Registration and Certification.

4. If an entity is part of a class of entities excluded based on the criteria above as individually being unlikely to have a material impact on the reliability of the bulk power system, but that in aggregate have been demonstrated to have such an impact it may be registered for applicable standards and requirements irrespective of other considerations.

Appendix 3 — Proposed Standards Authorization Request and Redline Standard Revisions

E-mail completed form to
maureen.long@nerc.net

Standard Authorization Request Form

Title of Proposed Standard Requirements	Various Standards Containing GO/GOP and TO/TOP
Request Date	~~October 30, 2009~~November 16, 2009
SC Approval Date	

SAR Requester Information	**SAR Type** (*Check a box for each one that applies.*)	
Name Ad Hoc Group for Generator Requirements at the Transmission Interface	☐	New Standard
Primary Contact Scott Helyer	☒	Revision to existing Standard
Telephone 817-462-1512 Fax	☐	Withdrawal of existing Standard
E-mail shelyer@tnsk.com	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.) The proposed changes to the requirements and the addition of new requirements will add significant clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid.
Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.) Significant industry concern exists regarding the application of Transmission Owner and Transmission Operator requirements, and more generally, to the registration of Generator Owners and Generator Operators as Transmission Owners and Transmission Operators, based on the facilities that connect the generators to the interconnected grid. The final report of the Ad Hoc Group for Generator Requirements at the Transmission Interface evaluated the issue and proposes a number of changes that adds much needed clarity on the requirements for Generator Interconnection Facilities. Absent these revisions and additional requirements, Generator Owners and Generator Operators are subject to what some believe to be inappropriate registration as Transmission Owners and Transmission Operators to ensure coverage for certain reliability requirements. The modifications and additions recommended wholly and directly address the requirements for Generator Owners and Generator Operators regarding its Generator Interconnection Facilities, and add particular focus on the operation of the interface point at which operating responsibility shifts from the GEnerator Operator to the Transmission Operator. The proposal also modifies certain of NERC's existing gloassary terms and adds new terms to support the standards modifications.
Brief Description (Provide a paragraph that describes the scope of this standard action.) 32 NERC Reliability Standards contain language regarding generators or generating facilities for which greater clarity regarding its Generator Interconnection Facilities would ensure no reliability gap exists 12 requirements in FAC-003-1 - Transmission Vegetation Management should have their applicability expanded to include Generator Owners. 2 NERC Reliability Standards should have their applicability expanded to include Generator Operators to address general reliability gaps not attributable to their Generator Interconnection Facilities. 8 new Reliability Standard Requirements should be added to ensure the responsibilities for owning and operating the Generator Interconnection Facility are clear, and to address certain requirements that should apply to all generators regardless of interconnection configuration. New NERC Glossary definitions are needed for Generator Interconnection Facility and Generator Interconnection Operational Interface, as well as modifications to Vegetation Inspection, Right-of-Way, Generator Owner, Generator Operator, and Transmission
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.) Refer to Final Report of the Ad hoc Group for Generator Requirements at the Transmission Interface.

Revisions to the latest versions of the following standards are included in the report and redline standard changes are included to accompany this SAR: BAL-005 CIP-002 EOP-001, -003, -004, -008 FAC-001, -003, -008, -009 IRO-005 MOD-010, -012 PER-001, -002 PRC-001, -004, -005 TOP-001, -002, -003, -004, -008 VAR-001, -002

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Assurer	Monitors and evaluates the activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within its portion of the Planning Coordinator's Area.
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within the Transmission Planner Area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☒	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

A. Introduction

1. **Title:** **Automatic Generation Control**

2. **Number:** BAL-005-0.1b

3. **Purpose:**

   This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.

4. **Applicability:**

   4.1. Balancing Authorities

   4.2. Generator Operators

   4.3. Transmission Operators

   4.4. Load Serving Entities

5. **Effective Date:** ~~May 13, 2009~~TBD

B. Requirements

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

R1.1. Each Generator Operator with generation facilities, including its Generator Interconnection Facility, operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.

R1.2. Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.

R1.3. Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.

R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.

R3. A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.

R4. A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.

R5. A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.

R6. The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.

R7. The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.

R8. The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.

R8.1. Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.

R9. The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.

R9.1. Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.

R10. The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.

R11. Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.

R12. Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.

R12.1. Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.

R12.2. Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.

R12.3. Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.

R13. Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (I_{ME}) term of the ACE equation to compensate for any equipment error until repairs can be made.

R14. The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.

R15. The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.

R16. The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25 % of full scale
Remote terminal unit	≤ 0.25 % of full scale
Potential transformer	≤ 0.30 % of full scale
Current transformer	≤ 0.50 % of full scale

C. Measures

Not specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Balancing Authorities shall be prepared to supply data to NERC in the format defined below:

1.1.1. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization CPS source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Error.

1.1.2. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to thirty minutes after the identified Disturbance.

1.2. Compliance Monitoring Period and Reset Timeframe

Not specified.

1.3. Data Retention

1.3.1. Each Balancing Authority shall retain its ACE, actual frequency, Scheduled Frequency, Net Actual Interchange, Net Scheduled Interchange, Tie Line meter error correction and Frequency Bias Setting data in digital format at the same scan rate at which the data is collected for at least one year.

1.3.2. Each Balancing Authority or Reserve Sharing Group shall retain documentation of the magnitude of each Reportable Disturbance as well as the ACE charts and/or samples used to calculate Balancing Authority or Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

Not specified.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 – Interpretation of Requirement R17 (February 12, 2008).

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Addition
0a	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial.	Errata
0b	February 12, 2008	Replaced Appendix 1 – Interpretation of R17 approved by BOT on February 12, 2008.	Replacement
0.1b	October 29, 2008	BOT approved errata changes; updated version number to “0.1b”	Errata
0.1b	May 13, 2009	FERC approved – Updated Effective Date and Footer	Addition
1b	TBD	Modified R1.1 to include its Generator Interconnection Facility	Addition

Appendix 1

Request: *PGE requests clarification regarding the measuring devices for which the requirement applies, specifically clarification if the requirement applies to the following measuring devices:*

- *Only equipment within the operations control room*
- *Only equipment that provides values used to calculate AGC ACE*
- *Only equipment that provides values to its SCADA system*
- *Only equipment owned or operated by the BA*
- *Only to new or replacement equipment*
- *To all equipment that a BA owns or operates*

BAL-005-1

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	$\leq$ 0.001 Hz
MW, MVAR, and voltage transducer	$\leq$ 0.25% of full scale
Remote terminal unit	$\leq$ 0.25% of full scale
Potential transformer	$\leq$ 0.30% of full scale
Current transformer	$\leq$ 0.50% of full scale

Existing Interpretation Approved by Board of Trustees May 2, 2007

BAL-005-0, Requirement 17 requires that the Balancing Authority check and calibrate its control room time error and frequency devices against a common reference at least annually. The requirement to “annually check and calibrate” does not address any devices outside of the operations control room.

The table represents the design accuracy of the listed devices. There is no requirement within the standard to “annually check and calibrate” the devices listed in the table, unless they are included in the control center time error and frequency devices.

Interpretation:

As noted in the existing interpretation, BAL-005-1 Requirement 17 applies only to the time error and frequency devices that provide, or in the case of back-up equipment may provide, input into the reporting or compliance ACE equation or provide real-time time error or frequency information to the system operator. Frequency inputs from other sources that are for reference only are excluded. The time error and frequency measurement devices may not necessarily be located in the system operations control room or owned by the Balancing Authority; however the Balancing Authority has the responsibility for the accuracy of the frequency and time error measurement devices. No other devices are included in R 17. The other devices listed in the table at the end of R17 are for reference only and do not have any mandatory calibration or accuracy requirements.

New or replacement equipment that provides the same functions noted above requires the same calibrations. Some devices used for time error and frequency measurement cannot be calibrated as such. In this case, these devices should be cross-checked against other properly calibrated equipment and replaced if the devices do not meet the required level of accuracy.

A. Introduction

1. **Title:** Cyber Security — Critical Cyber Asset Identification

2. **Number:** CIP-002-X~~1~~

3. **Purpose:** NERC Standards CIP-002 through CIP-009 provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

   These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed. Responsible Entities should interpret and apply Standards CIP-002 through CIP-009 using reasonable business judgment.

   Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

   Standard CIP-002 requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

4. **Applicability:**

   4.1. Within the text of Standard CIP-002, "Responsible Entity" shall mean:

   4.1.1 Reliability Coordinator.

   4.1.2 Balancing Authority.

   4.1.3 Interchange Authority.

   4.1.4 Transmission Service Provider.

   4.1.5 Transmission Owner.

   4.1.6 Transmission Operator.

   4.1.7 Generator Owner.

   4.1.8 Generator Operator.

   4.1.9 Load Serving Entity.

   4.1.10 NERC.

   4.1.11 Regional Reliability Organizations.

   4.2. The following are exempt from Standard CIP-002:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

5. **Effective Date:** ~~June 1, 2006~~TBD

B. Requirements

The Responsible Entity shall comply with the following requirements of Standard CIP-002:

R1. Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.

R1.1. The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.

R1.2. The risk-based assessment shall consider the following assets:

R1.2.1. Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.

R1.2.2. Transmission substations that support the reliable operation of the Bulk Electric System.

R1.2.3. Generation resources, including the Generator Interconnection Facility, that support the reliable operation of the Bulk Electric System.

R1.2.4. Systems and facilities critical to system restoration, including blackstart generators and their attendant Generator Interconnection Facility, and substations in the electrical path of transmission lines used for initial system restoration.

R1.2.5. Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

R1.2.6. Special Protection Systems that support the reliable operation of the Bulk Electric System.

R1.2.7. Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.

R2. Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.

R3. Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

R3.1. The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,

R3.2. The Cyber Asset uses a routable protocol within a control center; or,

R3.3. The Cyber Asset is dial-up accessible.

R4. Annual Approval — A senior manager or delegate(s) shall approve annually the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

C. Measures

The following measures will be used to demonstrate compliance with the requirements of Standard CIP-002:

M1. The risk-based assessment methodology documentation as specified in Requirement R1.

M2. The list of Critical Assets as specified in Requirement R2.

M3. The list of Critical Cyber Assets as specified in Requirement R3.

M4. The records of annual approvals as specified in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

1.1.1 Regional Reliability Organizations for Responsible Entities.

1.1.2 NERC for Regional Reliability Organization.

1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually.

1.3. Data Retention

1.3.1 The Responsible Entity shall keep documentation required by Standard CIP-002 from the previous full calendar year

1.3.2 The compliance monitor shall keep audit records for three calendar years.

1.4. Additional Compliance Information

1.4.1 Responsible Entities shall demonstrate compliance through self-certification or audit, as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1 Level 1: The risk assessment has not been performed annually.

2.2 Level 2: The list of Critical Assets or Critical Cyber Assets exist, but has not been approved or reviewed in the last calendar year.

2.3 Level 3: The list of Critical Assets or Critical Cyber Assets does not exist.

2.4 Level 4: The lists of Critical Assets and Critical Cyber Assets do not exist.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	01/16/06	R3.2 — Change “Control Center” to “control center”	03/24/06
X	TBD	Modified R1.2.3 to include the Generator Interconnection Facility and R1.2.4 to	Addition

		include a Generator Interconnection Facility	

A. Introduction

1. **Title:** **Emergency Operations Planning**

2. **Number:** EOP-001-X~~0~~

3. **Purpose:** Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.

4. **Applicability**

   4.1. Balancing Authorities.

   4.2. Transmission Operators.

5. **Effective Date:** ~~April 1, 2005~~TBD

B. Requirements

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

R2. The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.

R3. Each Transmission Operator and Balancing Authority shall:

R3.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.

R3.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.

R3.3. Develop, maintain, and implement a set of plans for load shedding.

R3.4. Develop, maintain, and implement a set of plans for system restoration.

R4. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:

R4.1. Communications protocols to be used during emergencies.

R4.2. A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.

R4.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.

R4.4. Staffing levels for the emergency.

R5. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-0 when developing an emergency plan.

R6. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.

R7. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:

R7.1. The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.

R7.2. The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.

R7.3. The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules, including outages to the Generator Interconnection Facility, ~~-~~to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)

R7.4. The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

C. Measures

M1. The Transmission Operator and Balancing Authority shall have its emergency plans available for review by the Regional Reliability Organization at all times.

M2. The Transmission Operator and Balancing Authority shall have its two most recent annual self-assessments available for review by the Regional Reliability Organization at all times.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframes

The Regional Reliability Organization shall review and evaluate emergency plans every three years to ensure that the plans consider the applicable elements of Attachment 1-EOP-001-0.

The Regional Reliability Organization may elect to request self-certification of the Transmission Operator and Balancing Authority in years that the full review is not done.

Reset: one calendar year.

1.3. Data Retention

Current plan available at all times.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: One of the applicable elements of Attachment 1-EOP-001-~~0~~X has not been addressed in the emergency plans.

2.2. Level 2: Two of the applicable elements of Attachment 1-EOP-001-~~0~~X have not been addressed in the emergency plans.

2.3. Level 3: Three of the applicable elements of Attachment 1-EOP-001-X~~0~~ have not been addressed in the emergency plans.

2.4. Level 4: Four or more of the applicable elements of Attachment 1-EOP-001-~~0~~X have not been addressed in the emergency plans or a plan does not exist.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
X	TBD	Modified R7.3 to include the Generator Interconnection Facility	Addition

Attachment 1-EOP-001-~~0~~X

Elements for Consideration in Development of Emergency Plans

1. Fuel supply and inventory — An adequate fuel supply and inventory plan that recognizes reasonable delays or problems in the delivery or production of fuel.

2. Fuel switching — Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.

3. Environmental constraints — Plans to seek removal of environmental constraints for generating units and plants.

4. System energy use — The reduction of the system's own energy use to a minimum.

5. Public appeals — Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

6. Load management — Implementation of load management and voltage reductions, if appropriate.

7. Optimize fuel supply — The operation of all generating sources to optimize the availability.

8. Appeals to customers to use alternate fuels — In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

9. Interruptible and curtailable loads — Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

10. Maximizing generator output and availability — The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

11. Notifying IPPs — Notification of cogeneration and independent power producers to maximize output and availability.

12. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

13. Load curtailment — A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

14. Notification of government agencies — Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

15. Notifications to operating entities — Notifications to other operating entities as steps in emergency plan are implemented.

A. Introduction

1. **Title:** **Load Shedding Plans**

2. **Number:** EOP-003-X~~1~~

3. **Purpose:** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

   4.3. Generator Operators.

5. **Effective Date:** ~~January 1, 2007~~TBD

B. Requirements

R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

R2. Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions.

R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected Transmission Operators and Balancing Authorities.

R4. A Transmission Operator or Balancing Authority shall consider one or more of these factors in designing an automatic load shedding scheme: frequency, rate of frequency decay, voltage level, rate of voltage decay, or power flow levels.

R5. A Transmission Operator or Balancing Authority shall implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.

R7. The Transmission Operator, Generator Operator, ~~-~~and Balancing Authority shall coordinate automatic load shedding throughout their areas with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions.

R8. Each Transmission Operator or Balancing Authority shall have plans for operator-controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.

C. Measures

M1. Each Transmission Operator and Balancing Authority that has or directs the deployment of undervoltage and/or underfrequency load shedding facilities, shall have and provide upon request, its automatic load shedding plans.(Requirement 2)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request its manual load shedding plans that will be used to confirm that it meets Requirement 8. (Part 1)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Additional Reporting Requirement

No additional reporting required.

1.4. Data Retention

Each Balancing Authority and Transmission Operator shall have its current, in-force load shedding plans.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor, The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.5. Additional Compliance Information

None.

2. Levels of Non-Compliance:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not Applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Does not have an automatic load shedding plan as specified in R2.

2.4.2 Does not have manual load shedding plans as specified in R8.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
X	TBD	Modified R7 to include Generator Operator. Added Generator Operator to Applicability Section.	Addition

A. Introduction

1. Title: **Disturbance Reporting**

2. Number: EOP-004-X~~1~~

3. Purpose: Disturbances or unusual occurrences that jeopardize the operation of the Bulk Electric System, or result in system equipment damage or customer interruptions, need to be studied and understood to minimize the likelihood of similar events in the future.

4. Applicability

4.1. Reliability Coordinators.

4.2. Balancing Authorities.

4.3. Transmission Operators.

4.4. Generator Operators.

4.5. Load Serving Entities.

4.6. Regional Reliability Organizations.

5. Effective Date: ~~January 1, 2007~~TBD

B. Requirements

R1. Each Regional Reliability Organization shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final disturbance reports.

R2. A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity shall promptly analyze Bulk Electric System disturbances on its system or facilities, including those for the Generator Interconnection Facility.~~.~~

R3. A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity experiencing a reportable incident shall provide a preliminary written report to its Regional Reliability Organization and NERC.

R3.1. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity shall submit within 24 hours of the disturbance or unusual occurrence either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report form. Events that are not identified until some time after they occur shall be reported within 24 hours of being recognized.

R3.2. Applicable reporting forms are provided in Attachments 1-EOP-004 and 2-EOP-004.

R3.3. Under certain adverse conditions, e.g., severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Interconnection Reliability Operating Limit and Preliminary Disturbance Report within 24 hours. In such cases, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall promptly notify its Regional Reliability Organization(s) and NERC, and verbally provide as much information as is available at that time. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.

R3.4. If, in the judgment of the Regional Reliability Organization, after consultation with the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity in which a disturbance occurred, a final report is required, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall prepare this report within 60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent recurrence of this type of event. The report shall be subject to Regional Reliability Organization approval.

R4. When a Bulk Electric System disturbance occurs, the Regional Reliability Organization shall make its representatives on the NERC Operating Committee and Disturbance Analysis Working Group available to the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity immediately affected by the disturbance for the purpose of providing any needed assistance in the investigation and to assist in the preparation of a final report.

R5. The Regional Reliability Organization shall track and review the status of all final report recommendations at least twice each year to ensure they are being acted upon in a timely manner. If any recommendation has not been acted on within two years, or if Regional Reliability Organization tracking and review indicates at any time that any recommendation is not being acted on with sufficient diligence, the Regional Reliability Organization shall notify the NERC Planning Committee and Operating Committee of the status of the recommendation(s) and the steps the Regional Reliability Organization has taken to accelerate implementation.

C. Measures

M1. The Regional Reliability Organization shall have and provide upon request as evidence, its current regional reporting procedure that is used to facilitate preparation of preliminary and final disturbance reports. (Requirement 1)

M2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity that has a reportable incident shall have and provide upon request evidence that could include, but is not limited to, the preliminary report, computer printouts, operator logs, or other equivalent evidence that will be used to confirm that it prepared and delivered the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Reports to NERC within 24 hours of its recognition as specified in Requirement 3.1.

M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and/or Load Serving Entity that has a reportable incident shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it provided information verbally as time permitted, when system conditions precluded the preparation of a report in 24 hours. (Requirement 3.3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

NERC shall be responsible for compliance monitoring of the Regional Reliability Organizations.

Regional Reliability Organizations shall be responsible for compliance monitoring of Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, and Load-serving Entities.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Regional Reliability Organization shall have its current, in-force, regional reporting procedure as evidence of compliance. (Measure 1)

Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and/or Load Serving Entity that is either involved in a Bulk Electric System disturbance or has a reportable incident shall keep data related to the incident for a year from the event or for the duration of any regional investigation, whichever is longer. (Measures 2 through 4)

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor, The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

See Attachments:

- EOP-004 Disturbance Reporting Form
- Table 1 EOP-004

2. Levels of Non-Compliance for a Regional Reliability Organization

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: No current procedure to facilitate preparation of preliminary and final disturbance reports as specified in R1.

3. Levels of Non-Compliance for a Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load- Serving Entity:

3.1. Level 1: There shall be a level one non-compliance if any of the following conditions exist:

3.1.1 Failed to prepare and deliver the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Reports to NERC within 24 hours of its recognition as specified in Requirement 3.1

3.1.2 Failed to provide disturbance information verbally as time permitted, when system conditions precluded the preparation of a report in 24 hours as specified in R3.3

3.1.3 Failed to prepare a final report within 60 days as specified in R3.4

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable

3.4. Level 4: Not applicable.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	May 23, 2005	Fixed reference to attachments 1-EOP-004-0 and 2-EOP-004-0, Changed chart title 1-FAC-004-0 to 1-EOP-004-0, Fixed title of Table 1 to read 1-EOP-004-0, and fixed font.	Errata
0	July 6, 2005	Fixed email in Attachment 1-EOP-004-0 from info@nerc.com to esisac@nerc.com.	Errata

0	July 26, 2005	Fixed Header on page 8 to read EOP-004-0	Errata
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
X	TBD	Modified R2 to include the Generator Interconnection Facility.	Addition

Attachment 1-EOP-004
NERC Disturbance Report Form

Introduction

These disturbance reporting requirements apply to all Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, and Load Serving Entities, and provide a common basis for all NERC disturbance reporting. The entity on whose system a reportable disturbance occurs shall notify NERC and its Regional Reliability Organization of the disturbance using the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report forms. Reports can be sent to NERC via email (esisac@nerc.com) by facsimile (609-452-9550) using the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report forms. If a disturbance is to be reported to the U.S. Department of Energy also, the responding entity may use the DOE reporting form when reporting to NERC. Note: All Emergency Incident and Disturbance Reports (Schedules 1 and 2) sent to DOE shall be simultaneously sent to NERC, preferably electronically at esisac@nerc.com.

The NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Reports are to be made for any of the following events:

1. The loss of a bulk power transmission component that significantly affects the integrity of interconnected system operations. Generally, a disturbance report will be required if the event results in actions such as:
   a. Modification of operating procedures.
   b. Modification of equipment (e.g. control systems or special protection systems) to prevent reoccurrence of the event.
   c. Identification of valuable lessons learned.
   d. Identification of non-compliance with NERC standards or policies.
   e. Identification of a disturbance that is beyond recognized criteria, i.e. three-phase fault with breaker failure, etc.
   f. Frequency or voltage going below the under-frequency or under-voltage load shed points.
2. The occurrence of an interconnected system separation or system islanding or both.
3. Loss of generation by a Generator Operator, Balancing Authority, or Load-Serving Entity — 2,000 MW or more in the Eastern Interconnection or Western Interconnection and 1,000 MW or more in the ERCOT Interconnection.
4. Equipment failures/system operational actions which result in the loss of firm system demands for more than 15 minutes, as described below:
   a. Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demands totaling more than 300 MW.
   b. All other entities are required to report all such losses of firm demands totaling more than 200 MW or 50% of the total customers being supplied immediately prior to the incident, whichever is less.
5. Firm load shedding of 100 MW or more to maintain the continuity of the bulk electric system.

6. Any action taken by a Generator Operator, Transmission Operator, Balancing Authority, or Load-Serving Entity that results in:
   a. Sustained voltage excursions equal to or greater than ±10%, or
   b. Major damage to power system components, or
   c. Failure, degradation, or misoperation of system protection, special protection schemes, remedial action schemes, or other operating systems that do not require operator intervention, which did result in, or could have resulted in, a system disturbance as defined by steps 1 through 5 above.
7. An Interconnection Reliability Operating Limit (IROL) violation as required in reliability standard TOP-007.
8. Any event that the Operating Committee requests to be submitted to Disturbance Analysis Working Group (DAWG) for review because of the nature of the disturbance and the insight and lessons the electricity supply and delivery industry could learn.

NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report

☐ Check here if this is an Interconnection Reliability Operating Limit (IROL) violation report.

1.	Organization filing report.		
2.	Name of person filing report.		
3.	Telephone number.		
4.	Date and time of disturbance. Date:(mm/dd/yy) Time/Zone:		
5.	Did the disturbance originate in your system?	Yes ☐ No ☐	
6.	Describe disturbance including: cause, equipment damage, critical services interrupted, system separation, key scheduled and actual flows prior to disturbance and in the case of a disturbance involving a special protection or remedial action scheme, what action is being taken to prevent recurrence.		
7.	Generation tripped. MW Total List generation tripped		
8.	Frequency. Just prior to disturbance (Hz): Immediately after disturbance (Hz max.): Immediately after disturbance (Hz min.):		
9.	List transmission lines tripped (specify voltage level of each line).		
10.		FIRM	INTERRUPTIBLE
	Demand tripped (MW):		
	Number of affected Customers:		

	Demand lost (MW-Minutes):		
11.	Restoration time.	INITIAL	FINAL
	Transmission:		
	Generation:		
	Demand:		

Attachment 2-EOP-004
U.S. Department of Energy Disturbance Reporting Requirements

Introduction

The U.S. Department of Energy (DOE), under its relevant authorities, has established mandatory reporting requirements for electric emergency incidents and disturbances in the United States. DOE collects this information from the electric power industry on Form EIA-417 to meet its overall national security and Federal Energy Management Agency's Federal Response Plan (FRP) responsibilities. DOE will use the data from this form to obtain current information regarding emergency situations on U.S. electric energy supply systems. DOE's Energy Information Administration (EIA) will use the data for reporting on electric power emergency incidents and disturbances in monthly EIA reports. In addition, the data may be used to develop legislative recommendations, reports to the Congress and as a basis for DOE investigations following severe, prolonged, or repeated electric power reliability problems.

Every Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity must use this form to submit mandatory reports of electric power system incidents or disturbances to the DOE Operations Center, which operates on a 24-hour basis, seven days a week. All other entities operating electric systems have filing responsibilities to provide information to the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity when necessary for their reporting obligations and to file form EIA-417 in cases where these entities will not be involved. EIA requests that it be notified of those that plan to file jointly and of those electric entities that want to file separately.

Special reporting provisions exist for those electric utilities located within the United States, but for whom Reliability Coordinator oversight responsibilities are handled by electrical systems located across an international border. A foreign utility handling U.S. Balancing Authority responsibilities, may wish to file this information voluntarily to the DOE. Any U.S.-based utility in this international situation needs to inform DOE that these filings will come from a foreign-based electric system or file the required reports themselves.

Form EIA-417 must be submitted to the DOE Operations Center if any one of the following applies (see Table 1-EOP-004-0 — Summary of NERC and DOE Reporting Requirements for Major Electric System Emergencies):

1. Uncontrolled loss of 300 MW or more of firm system load for more than 15 minutes from a single incident.
2. Load shedding of 100 MW or more implemented under emergency operational policy.
3. System-wide voltage reductions of 3 percent or more.
4. Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system.
5. Actual or suspected physical attacks that could impact electric power system adequacy or reliability; or vandalism, which target components of any security system. Actual or suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability.

6. Actual or suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability.
7. Fuel supply emergencies that could impact electric power system adequacy or reliability.
8. Loss of electric service to more than 50,000 customers for one hour or more.
9. Complete operational failure or shut-down of the transmission and/or distribution electrical system.

The initial DOE Emergency Incident and Disturbance Report (form EIA-417 – Schedule 1) shall be submitted to the DOE Operations Center within 60 minutes of the time of the system disruption. Complete information may not be available at the time of the disruption. However, provide as much information as is known or suspected at the time of the initial filing. If the incident is having a critical impact on operations, a telephone notification to the DOE Operations Center (202-586-8100) is acceptable, pending submission of the completed form EIA-417. Electronic submission via an on-line web-based form is the preferred method of notification. However, electronic submission by facsimile or email is acceptable.

An updated form EIA-417 (Schedule 1 and 2) is due within 48 hours of the event to provide complete disruption information. Electronic submission via facsimile or email is the preferred method of notification. Detailed DOE Incident and Disturbance reporting requirements can be found at: ftp://ftp.eia.doe.gov/pub/electricity/eiafor417.doc.

Table 1-EOP-004-0 Summary of NERC and DOE Reporting Requirements for Major Electric System Emergencies				
Incident No.	**Incident**	**Threshold**	**Report Required**	**Time**
1	Uncontrolled loss of Firm System Load	≥ 300 MW – 15 minutes or more	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
2	Load Shedding	≥ 100 MW under emergency operational policy	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
3	Voltage Reductions	3% or more – applied system-wide	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
4	Public Appeals	Emergency conditions to reduce demand	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
5	Physical sabotage, terrorism or vandalism	On physical security systems – suspected or real	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
6	Cyber sabotage, terrorism or vandalism	If the attempt is believed to have or did happen	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
7	Fuel supply emergencies	Fuel inventory or hydro storage levels ≤ 50% of normal	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
8	Loss of electric service	≥ 50,000 for 1 hour or more	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
9	Complete operation failure of electrical system	If isolated or interconnected electrical systems suffer total electrical system collapse	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
All DOE EIA-417 Schedule 1 reports are to be filed within 60-minutes after the start of an incident or disturbance All DOE EIA-417 Schedule 2 reports are to be filed within 48-hours after the start of an incident or disturbance				

All entities required to file a DOE EIA-417 report (Schedule 1 & 2) shall send a copy of these reports to NERC simultaneously, but no later than 24 hours after the start of the incident or disturbance.				
Incident No.	**Incident**	**Threshold**	**Report Required**	**Time**
1	Loss of major system component	Significantly affects integrity of interconnected system operations	NERC Prelim Final report	24 hour 60 day
2	Interconnected system separation or system islanding	Total system shutdown Partial shutdown, separation, or islanding	NERC Prelim Final report	24 hour 60 day
3	Loss of generation	≥ 2,000 – Eastern Interconnection ≥ 2,000 – Western Interconnection ≥ 1,000 – ERCOT Interconnection	NERC Prelim Final report	24 hour 60 day
4	Loss of firm load ≥15-minutes	Entities with peak demand ≥3,000: loss ≥300 MW All others ≥200MW or 50% of total demand	NERC Prelim Final report	24 hour 60 day
5	Firm load shedding	≥100 MW to maintain continuity of bulk system	NERC Prelim Final report	24 hour 60 day
6	System operation or operation actions resulting in:	• Voltage excursions ≥10% • Major damage to system components • Failure, degradation, or misoperation of SPS	NERC Prelim Final report	24 hour 60 day
7	IROL violation	Reliability standard TOP-007.	NERC Prelim Final report	72 hour 60 day
8	As requested by ORS Chairman	Due to nature of disturbance & usefulness to industry (lessons learned)	NERC Prelim Final report	24 hour 60 day
All NERC Operating Security Limit and Preliminary Disturbance reports will be filed within 24 hours after the start of the incident. If an entity must file a DOE EIA-417 report on an incident, which requires a NERC Preliminary report, the Entity may use the DOE EIA-417 form for both DOE and NERC reports.				
Any entity reporting a DOE or NERC incident or disturbance has the responsibility to also notify its Regional Reliability Organization.				

A. Introduction

1. Title: **Plans for Loss of Control Center Functionality**

2. Number: EOP-008-X~~0~~

3. Purpose: Each reliability entity must have a plan to continue reliability operations in the event its control center becomes inoperable.

4. Applicability

4.1. Transmission Operators.

4.2. Balancing Authorities.

4.3. Reliability Coordinators.

5. Effective Date: ~~April 1, 2005~~TBD

B. Requirements

R1. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have a plan to continue reliability operations in the event its control center becomes inoperable. The contingency plan must meet the following requirements:

R1.1. The contingency plan shall not rely on data or voice communication from the primary control facility to be viable.

R1.2. The plan shall include procedures and responsibilities for providing basic tie line control and procedures and for maintaining the status of all inter-area schedules, such that there is an hourly accounting of all schedules.

R1.3. The contingency plan must address monitoring and control of critical transmission facilities, Generator Interconnection Operational Interface, generation control, voltage control, time and frequency control, control of critical substation devices, and logging of significant power system events. The plan shall list the critical facilities.

R1.4. The plan shall include procedures and responsibilities for maintaining basic voice communication capabilities with other areas.

R1.5. The plan shall include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan.

R1.6. The plan shall include procedures and responsibilities for providing annual training to ensure that operating personnel are able to implement the contingency plans.

R1.7. The plan shall be reviewed and updated annually.

R1.8. Interim provisions must be included if it is expected to take more than one hour to implement the contingency plan for loss of primary control facility.

C. Measures

M1. Evidence that the Reliability Coordinator, Transmission Operator or Balancing Authority has developed and documented a current contingency plan to continue the monitoring and operation of the electrical equipment under its control to maintain Bulk Electrical System reliability if its primary control facility becomes inoperable.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

Periodic Review: Review and evaluate the plan for loss of primary control facility contingency as part of the three-year on-site audit process. The audit must include a demonstration of the plan by the Reliability Coordinator, Transmission Operator, and Balancing Authority.

Reset: One calendar year.

1.3. Data Retention

The contingency plan for loss of primary control facility must be available for review at all times.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: NA

2.2. Level 2: A contingency plan has been implemented and tested, but has not been tested in the past year or there are no records of shift operating personnel training.

2.3. Level 3: A contingency plan has been implemented, but does not include all of the elements contained in Requirements R1.1–R1.8.

2.4. Level 4: A contingency plan has not been developed, implemented, and tested.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
X	TBD	Modified R1.3 to include Generator Interconnection Operational Interface	Addition

A. Introduction

1. **Title:** **Facility Connection Requirements**

2. **Number:** FAC-001-~~0~~ X

3. **Purpose:** To avoid adverse impacts on reliability, Transmission Owners must establish facility connection and performance requirements.

4. **Applicability:**

   4.1. Transmission Owner

5. **Effective Date:** ~~April 1, 2005~~TBD

B. Requirements

R1. The Transmission Owner shall document, maintain, and publish facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Reliability Organization, subregional, Power Pool, and individual Transmission Owner planning criteria and facility connection requirements. The Transmission Owner's facility connection requirements shall address connection requirements for:

R1.1. Generation facilities, including the Generator Interconnection Facility,

R1.2. Transmission facilities, and

R1.3. End-user facilities

R2. The Transmission Owner's facility connection requirements shall address, but are not limited to, the following items:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.

R2.1.2. Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as soon as feasible.

R2.1.3. Voltage level and MW and MVAR capacity or demand at point of connection.

R2.1.4. Breaker duty and surge protection.

R2.1.5. System protection and coordination.

R2.1.6. Metering and telecommunications.

R2.1.7. Grounding and safety issues.

R2.1.8. Insulation and insulation coordination.

R2.1.9. Voltage, Reactive Power, and power factor control.

R2.1.10. Power quality impacts.

R2.1.11. Equipment Ratings.

R2.1.12. Synchronizing of facilities.

R2.1.13. Maintenance coordination.

R2.1.14. Operational issues (abnormal frequency and voltages).

R2.1.15. Inspection requirements for existing or new facilities.

R2.1.16. Communications and procedures during normal and emergency operating conditions.

R3. The Transmission Owner shall maintain and update its facility connection requirements as required. The Transmission Owner shall make documentation of these requirements available to the users of the transmission system, the Regional Reliability Organization, and NERC on request (five business days).

C. Measures

M1. The Transmission Owner shall make available (to its Compliance Monitor) for inspection evidence that it met all the requirements stated in Reliability Standard FAC-001-0_R1.

M2. The Transmission Owner shall make available (to its Compliance Monitor) for inspection evidence that it met all requirements stated in Reliability Standard FAC-001-0_R2.

M3. The Transmission Owner shall make available (to its Compliance Monitor) for inspection evidence that it met all the requirements stated in Reliability Standard FAC-001-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (five business days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Facility connection requirements were provided for generation, transmission, and end-user facilities, per Reliability Standard FAC-001-0_R1, but the document(s) do not address all of the requirements of Reliability Standard FAC-001-0_R2.

2.2. Level 2: Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, per Reliability Standard FAC-001-0_R1, but the document(s) provided address all of the requirements of Reliability Standard FAC-001-0_R2.

2.3. Level 3: Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, per Reliability Standard FAC-001-0_R1, and the document(s) provided do not address all of the requirements of Reliability Standard FAC-001-0_R2.

2.4. **Level 4:** No document on facility connection requirements was provided per Reliability Standard FAC-001-0_R3.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
X	TBD	Modified R1.1 to include the Generator Interconnection Facility	Addition

A. Introduction

1. **Title:** **Transmission Vegetation Management Program**

2. **Number:** FAC-003-X~~1~~

3. **Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the North American Electric Reliability Council (NERC).

4. **Applicability:**

   4.1. Transmission Owner.

   4.2. Regional Reliability Organization.

   4.3. This standard shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region.

   4.4. Generator Owner.

   4.5. This standard shall apply to the Generator Interconnection Facility above 200 kV that exceed two spans from the generator property line or are otherwise deemed critical by the Regional Entity below 200 kV (subject to the two-span criteria.)

5. **Effective Dates:**

   ~~**5.1.**One calendar year from the date of adoption by the NERC Board of Trustees for Requirements 1 and 2.~~

   ~~**5.2.**~~**5.1.** ~~Sixty calendar days from the date of adoption by the NERC Board of Trustees for Requirements 3 and 4.~~TBD

B. Requirements

R1. The Transmission Owner and Generator Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the Transmission Owner's and Generator Owner's objectives, practices, approved procedures, and work specifications[1].

R1.1. The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's or Generator Owner's transmission lines.

R1.2. The Transmission Owner and Generator Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner and Generator Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of

[1] ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

R1.2.1. Clearance 1 — The Transmission Owner and Generator Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner or Generator Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

R1.2.2. Clearance 2 — The Transmission Owner and Generator Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific and Generator Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

R1.2.2.1 Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

R1.2.2.2 Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

R1.3. All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner or Generator Owner, to perform their duties.

R1.4. Each Transmission Owner and Generator Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner or Generator Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

R1.5. Each Transmission Owner and Generator Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

R2. The Transmission Owner and Generator Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner and Generator Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

R3. The Transmission Owner and Generator Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner or Generator Owner to have been caused by vegetation.

R3.1. Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period.

R3.2. The Transmission Owner or Generator Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner, Generator Owner, or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).

R3.3. The outage information provided by the Transmission Owner or Generator Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner or Generator Owner.

R3.4. An outage shall be categorized as one of the following:

R3.4.1. Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;

R3.4.2. Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

R3.4.3. Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

R4. The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.

C. Measures

M1. The Transmission Owner has a documented TVMP, as identified in Requirement 1.

M1.1. The Transmission Owner has documentation that the Transmission Owner performed the vegetation inspections as identified in Requirement 1.1.

M1.2. The Transmission Owner has documentation that describes the clearances identified in Requirement 1.2.

M1.3. The Transmission Owner has documentation that the personnel directly involved in the design and implementation of the Transmission Owner's TVMP hold the qualifications identified by the Transmission Owner as required in Requirement 1.3.

M1.4. The Transmission Owner has documentation that it has identified any areas not meeting the Transmission Owner's standard for vegetation management and any mitigating measures the Transmission Owner has taken to address these deficiencies as identified in Requirement 1.4.

M1.5. The Transmission Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.

M2. The Transmission Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.

M3. The Transmission Owner has documentation that it has supplied quarterly outage reports to the RRO, or the RRO's designee, as identified in Requirement 3.

M4. The RRO has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

RRO

NERC

1.2. Compliance Monitoring Period and Reset

One calendar Year

1.3. Data Retention

Five Years

1.4. Additional Compliance Information

The Transmission Owner shall demonstrate compliance through self-certification submitted to the compliance monitor (RRO) annually that it meets the requirements of NERC Reliability Standard FAC-003-1. The compliance monitor shall conduct an on-site audit every five years or more frequently as deemed appropriate by the compliance monitor to review documentation related to Reliability Standard FAC-003-1. Field audits of ROW vegetation conditions may be conducted if determined to be necessary by the compliance monitor.

2. Levels of Non-Compliance

2.1. Level 1:

2.1.1. The TVMP was incomplete in one of the requirements specified in any subpart of Requirement 1, or;

2.1.2. Documentation of the annual work plan, as specified in Requirement 2, was incomplete when presented to the Compliance Monitor during an on-site audit, or;

2.1.3. The RRO provided an outage report to NERC that was incomplete and did not contain the information required in Requirement 4.

2.2. Level 2:

2.2.1. The TVMP was incomplete in two of the requirements specified in any subpart of Requirement 1, or;

2.2.2. The Transmission Owner was unable to certify during its annual self-certification that it fully implemented its annual work plan, or documented deviations from, as specified in Requirement 2.

2.2.3. The Transmission Owner reported one Category 2 transmission vegetation-related outage in a calendar year.

2.3. Level 3:

2.3.1. The Transmission Owner reported one Category 1 or multiple Category 2 transmission vegetation-related outages in a calendar year, or;

2.3.2. The Transmission Owner did not maintain a set of clearances (Clearance 2), as defined in Requirement 1.2.2, to prevent flashover between vegetation and overhead ungrounded supply conductors, or;

2.3.3. The TVMP was incomplete in three of the requirements specified in any subpart of Requirement 1.

2.4. Level 4:

2.4.1. The Transmission Owner reported more than one Category 1 transmission vegetation-related outage in a calendar year, or;

2.4.2. The TVMP was incomplete in four or more of the requirements specified in any subpart of Requirement 1.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
1	TBA	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	01/20/06
X	TBD	Modified the Applicability Section to include the Generator Owner and Generator Interconnection Facility above 200 kV that exceed two spans from the generator property line or are otherwise deemed critical by the Regional Entity below 200 kV (subject to the two-span criteria.). Included Generator Owner into the following Requirements: R1, R1.1, R1.2, R1.2.1, R1.2.2, R1.3, R1.4, R1.5, R2, R3,	Addition

		R3.2, and R3.3	

A. Introduction

1. **Title:** **Facility Ratings Methodology**

2. **Number:** FAC-008-X~~1~~

3. **Purpose:** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability**

   4.1. Transmission Owner

   4.2. Generator Owner

5. **Effective Date:** ~~August 7, 2006~~TBD

B. Requirements

R1. The Transmission Owner and Generator Owner shall each document its current methodology used for developing Facility Ratings (Facility Ratings Methodology) of its solely and jointly owned Facilities, including the Generator Interconnection Facility. The methodology shall include all of the following:

R1.1. A statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

R1.2. The method by which the Rating (of major BES equipment that comprises a Facility) is determined.

R1.2.1. The scope of equipment addressed shall include, but not be limited to, generators, the Generator Interconnection Facility, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

R1.2.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

R1.3. Consideration of the following:

R1.3.1. Ratings provided by equipment manufacturers.

R1.3.2. Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer's warranty, IEEE, ANSI or other standards).

R1.3.3. Ambient conditions.

R1.3.4. Operating limitations.

R1.3.5. Other assumptions.

R2. The Transmission Owner and Generator Owner shall each make its Facility Ratings Methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated Facilities are located, within 15 business days of receipt of a request.

R3. If a Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides written comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall provide a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.

C. Measures

M1. The Transmission Owner and Generator Owner shall each have a documented Facility Ratings Methodology that includes all of the items identified in FAC-008 Requirement 1.1 through FAC-008 Requirement 1.3.5.

M2. The Transmission Owner and Generator Owner shall each have evidence it made its Facility Ratings Methodology available for inspection within 15 business days of a request as follows:

M2.1 The Reliability Coordinator shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Reliability Coordinator Area.

M2.2 The Transmission Operator shall have access to the Facility Ratings Methodologies used for Rating Facilities in its portion of the Reliability Coordinator Area.

M2.3 The Transmission Planner shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Transmission Planning Area.

M2.4 The Planning Authority shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Planning Authority Area.

M3. If the Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides documented comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall have evidence that it provided a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Transmission Owner and Generator Owner shall self-certify its compliance to the Compliance Monitor at least once every three years. New Transmission Owners and Generator Owners shall each demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

The Transmission Owner and Generator Owner shall each keep all superseded portions of its Facility Ratings Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on the Facility Ratings Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Transmission Owner and Generator Owner shall each make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 Facility Ratings Methodology

1.4.2 Superseded portions of its Facility Ratings Methodology that had been replaced, changed or revised within the past 12 months

1.4.3 Documented comments provided by a Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Authority on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings methodology, and the associated responses

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if any of the following conditions exists:

2.1.1 The Facility Ratings Methodology does not contain a statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

2.1.2 The Facility Ratings Methodology does not address one of the required equipment types identified in FAC-008 R1.2.1.

2.1.3 No evidence of responses to a Reliability Coordinator's, Transmission Operator, Transmission Planner, or Planning Authority's comments on the Facility Ratings Methodology.

2.2. Level 2: The Facility Ratings Methodology is missing the assumptions used to determine Facility Ratings or does not address two of the required equipment types identified in FAC-008 R1.2.1.

2.3. Level 3: The Facility Ratings Methodology does not address three of the required equipment types identified in FAC-008-1 R1.2.1.

2.4. Level 4: The Facility Ratings Methodology does not address both Normal and Emergency Ratings or the Facility Ratings Methodology was not made available for inspection within 15 business days of receipt of a request.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
1	01/01/05	1. Lower cased the word "draft" and "drafting team" where appropriate. 2. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 3. Changed "Timeframe" to "Time	01/20/05

		Frame" and "twelve" to "12" in item D, 1.2.	
X	TBD	Modified R1 and R1.2.1 to include the Generator Interconnection Facility	Addition

A. Introduction

1. Title: **Establish and Communicate Facility Ratings**

2. Number: FAC-009-X~~1~~

3. Purpose: To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. Applicability

4.1. Transmission Owner

4.2. Generator Owner

5. Effective Date: ~~October 7, 2006~~TBD

B. Requirements

R1. The Transmission Owner and Generator Owner shall each establish Facility Ratings for its solely and jointly owned Facilities, including the Generator Interconnection Facility,~~-~~ that are consistent with the associated Facility Ratings Methodology.

R2. The Transmission Owner and Generator Owner shall each provide Facility Ratings for its solely and jointly owned Facilities, including the Generator Interconnection Facility, that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.

C. Measures

M1. The Transmission Owner and Generator Owner shall each be able to demonstrate that it developed its Facility Ratings consistent with its Facility Ratings Methodology.

M1.1 The Transmission Owner's and Generator Owner's Facility Ratings shall each include ratings for its solely and jointly owned Facilities including new Facilities, existing Facilities, modifications to existing Facilities and re-ratings of existing Facilities.

M2. The Transmission Owner and Generator Owner shall each have evidence that it provided its Facility Ratings to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Transmission Owner and Generator Owner shall self-certify its compliance to the Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January–December) and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Transmission Owner and Generator Owner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall retain audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner and Generator Owner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 Facility Ratings Methodology

1.4.2 Facility Ratings

1.4.3 Evidence that Facility Ratings were distributed

1.4.4 Distribution schedules provided by entities that requested Facility Ratings

2. Levels of Non-Compliance

2.1. Level 1: Not all requested Facility Ratings associated with existing Facilities were provided to the Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) in accordance with their respective schedules.

2.2. Level 2: Not all Facility Ratings associated with new Facilities, modifications to existing Facilities, and re-ratings of existing Facilities were provided to the Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) in accordance with their respective schedules.

2.3. Level 3: Facility Ratings provided were not developed consistent with the Facility Ratings Methodology.

2.4. Level 4: No Facility Ratings were provided to the Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), or Transmission Operator(s) in accordance with their respective schedules.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Lower cased the word “draft” and “drafting team” where appropriate. 2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
X	TBD	Modified R1 and R2 to include the Generator Interconnection Facility	Addition

A. Introduction

1. **Title:** **Reliability Coordination — Current Day Operations**

2. **Number:** IRO-005-X~~2~~

3. **Purpose:** The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.

4. **Applicability**

   4.1. Reliability Coordinators.

   4.2. Balancing Authorities.

   4.3. Transmission Operators.

   4.4. Transmission Service Providers.

   4.5. Generator Operators.

   4.6. Load-Serving Entities.

   4.7. Purchasing-Selling Entities.

5. **Effective Date:** ~~January 1, 2007~~TBD

B. Requirements

R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:

R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.

R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.

R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.

R1.4. System real and reactive reserves (actual versus required).

R1.5. Capacity and energy adequacy conditions.

R1.6. Current ACE for all its Balancing Authorities.

R1.7. Current local or Transmission Loading Relief procedures in effect.

R1.8. Planned generation dispatches.

R1.9. Planned transmission or generation outages.

R1.10. Contingency events.

R2. Each Reliability Coordinator shall be aware of all Interchange Transactions that wheel through, source, or sink in its Reliability Coordinator Area, and make that Interchange Transaction information available to all Reliability Coordinators in the Interconnection.

R3. As portions of the transmission system approach or exceed SOLs or IROLs, the Reliability Coordinator shall work with its Transmission Operators and Balancing Authorities to evaluate and assess any additional Interchange Schedules that would violate those limits. If a potential or actual IROL violation cannot be avoided through proactive intervention, the Reliability Coordinator shall initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall ensure all resources, including load shedding, are available to address a potential or actual IROL violation.

R4. Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.

R5. Each Reliability Coordinator shall identify the cause of any potential or actual SOL or IROL violations. The Reliability Coordinator shall initiate the control action or emergency procedure to relieve the potential or actual IROL violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall be able to utilize all resources, including load shedding, to address an IROL violation.

R6. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.

R7. The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.

R8. Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.

R9. The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages, including the Generator Interconnection Facility, with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.

R10. As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.

R11. The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.

R12. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.

R13. The Generator Operator shall immediately inform the Transmission Operator of the status of the Special Protection System, including any degradation or potential failure to operate as expected for SPS relay or control equipment under its control.

~~R13.~~R14. Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.

~~R14.~~R15. Each Reliability Coordinator shall make known to Transmission Service Providers within its Reliability Coordinator Area, SOLs or IROLs within its wide-area view. The Transmission Service Providers shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.

~~R15.~~R16. Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.

~~R16.~~R17. Each Reliability Coordinator shall confirm reliability assessment results and determine the effects within its own and adjacent Reliability Coordinator Areas. The Reliability Coordinator shall discuss options to mitigate potential or actual SOL or IROL violations and take actions as necessary to always act in the best interests of the Interconnection at all times.

~~R17.~~R18. When an IROL or SOL is exceeded, the Reliability Coordinator shall evaluate the local and wide-area impacts, both real-time and post-contingency, and determine if the actions being taken are appropriate and sufficient to return the system to within IROL in thirty minutes. If the actions being taken are not appropriate or sufficient, the Reliability Coordinator shall direct the Transmission Operator, Balancing Authority, Generator Operator, or Load-Serving Entity to return the system to within IROL or SOL.

C. Measures

M1. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, a prepared report specifically detailing compliance to each of the bullets in Requirement 1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors the Reliability Coordinator Area parameters specified in Requirements 1.1 through 1.9.

M2. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Historical Tag Archive information, Interchange Transaction records, computer printouts, voice recordings or transcripts of voice recordings or equivalent evidence that will be used to confirm that it was aware of and made Interchange Transaction information available to all other Reliability Coordinators, as specified in Requirement 2.

M3. If a potential or actual IROL violation occurs, the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, system event logs, operator action notes or equivalent evidence that will be used to determine if it initiated control actions or emergency procedures to relieve that IROL violation within 30 minutes. (Requirement 3 Part 2 and Requirement 5)

M4. If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to computer printouts, operating logs, voice recordings or transcripts of voice recordings, or equivalent evidence that will be used to determine if the Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 4 Part 2 and Requirement 10)

M5. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it informed Transmission Operators and Balancing Authorities of Geo-Magnetic Disturbance (GMD) forecast information and provided assistance as needed in the development of any required response plans. (Requirement 6)

M6. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it disseminated information within its Reliability Coordinator Area in accordance with Requirement 7.

M7. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it monitored system frequency and Balancing Authority performance and directed any necessary rebalancing, as specified in Requirement 8 Part 1.

M8. The Transmission Operators and Balancing Authorities shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it utilized all resources, including firm load shedding, as directed by its Reliability Coordinator, to relieve an emergent condition. (Requirement 8 Part 2)

M9. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or equivalent evidence that will be used to determine if it coordinated with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations including the coordination of pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities and Generator Operators. (Requirement 9 Part 1)

M10. If a large Area Control Error has occurred, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it identified sources of the Area Control Errors, and initiated corrective actions with the appropriate Balancing Authority if the problem was within the Reliability Coordinator's Area (Requirement 11 Part 1)

M11. If a Special Protection System is armed and that system could have had an inter-area impact, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, agreements with their Transmission Operators, procedural documents, operator logs, computer analysis, training modules, training records or equivalent evidence that will be used to confirm that it was aware of the impact of that Special Protection System on inter-area flows. (Requirement 12)

M12. If there is an instance where there is a disagreement on a derived limit, the Reliability Coordinator, Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider involved in the disagreement shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications or equivalent evidence that will be used to determine if it operated to the most limiting parameter. (Part 2 of Requirement 13)

M13. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it provided SOL and IROL information to Transmission Service Providers within its Reliability Coordinator Area. (Requirement 14, Part 1)

M14. The Transmission Service Providers shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it respected the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 14 Part 2)

M15. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it issued alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area, to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area as specified in Requirement 15 Part 1.

M16. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that upon receiving information such as an SOL or IROL violation, loss of reactive reserves, etc. it disseminated the information to its impacted Transmission Operators and Balancing Authorities as specified in Requirement 15 Part 2.

M17. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it notified all impacted Transmission Operators, Balancing Authorities and Reliability Coordinators when a transmission problem has been mitigated. (Requirement 15 Part 3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measures 1 and 11, each Reliability Coordinator shall have its current in-force documents as evidence.

For Measures 2–10 and Measure 13, and Measures 15 through 16, the Reliability Coordinator shall keep 90 days of historical data (evidence).

For Measure 8, the Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence).

For Measure 12, the Reliability Coordinator, Transmission Operator, Balancing Authority, and Transmission Service Provider shall keep 90 days of historical data (evidence).

For Measure 14, the Transmission Service Provider shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. **Levels of Non-Compliance for a Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider**

   2.1. Level 1: Not applicable.

   2.2. Level 2: Not applicable.

   2.3. Level 3: Not applicable.

   2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

      2.4.1 Did not follow the Reliability Coordinator's directives in accordance with R8 Part 2).

      2.4.2 Did not operate to the most limiting parameter when a difference in derived limits existed. (R13 Part 2)

3. **Levels of Non-Compliance for a Reliability Coordinator:**

   3.1. Level 1: Not applicable.

   3.2. Level 2: Did not make Interchange Transaction information available to all other Reliability Coordinators in the Interconnection. (Requirement 2)

   3.3. Level 3: There shall be a separate Level 3 non-compliance, for every one of the following requirements that is in violation:

      3.3.1 Did not communicate to each of its Balancing Authorities and Transmission Operators to make them aware of GMD forecast information or did not assist in the development of any required response plans to a predicted GMD. (Requirement 6)

      3.3.2 Did not disseminate information within its Reliability Coordinator Area. (Requirement 7)

   3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

      3.4.1 Does not meet one or more of the requirements as specified in requirement 1 (Requirements 1.1 through R1.9)

      3.4.2 Did not make Interchange Transaction information available to all other Reliability Coordinators. (Requirement 2)

      3.4.3 Did not initiate control actions or emergency procedures to relieve an IROL violation without delay, and no longer than 30 minutes. (Requirement 3 Part 2 and Requirement 5)

      3.4.4 Did not direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 4 Part 2)

      3.4.5 Did not monitor the system frequency or each of its Balancing Authorities performance or did not direct rebalancing to return to DCS and CPS compliance. (Requirement 8 Part 1)

      3.4.6 Did not coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. (Requirement 9)

3.4.7 When it identified a source of large Area Control Errors, it did not initiate corrective actions with the appropriate Balancing Authority if the problem was inside its Reliability Coordinator Area. (Requirement 11 part 1)

3.4.8 Did not provide evidence that it was aware of the impact of the operation of a Special Protection System on inter-area flows. (Requirement 12)

3.4.9 Did not operate to the most limiting parameter when a difference in derived limits existed. (Requirement 13 Part 2)

3.4.10 Did not provide Transmission Service Providers with SOLs or IROLs (within the Reliability Coordinator's wide-area view) (Requirement 14 Part 1)

3.4.11 Did not issue alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area. (Requirement 15)

4. Levels of Non-Compliance for a Transmission Service Provider

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

4.4.1 Did not operate to the most limiting parameter when a difference in derived limits existed. (R13 Part 2)

4.4.2 Did not respect the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 14 Part 2)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	February 2, 2006	Approved by Board of Trustees	Revised
2	August 31, 2006	Added three items that were inadvertently left out to "Applicability" section: 4.5 Generator Operators. 4.6 Load-Serving Entities. 4.7 Purchasing-Selling Entities	Errata
2	November 1, 2006	Approved by Board of Trustees	Revised
2	June 26, 2007	Approved by FERC:	Revised

		Missing Measures and Compliance Elements	
X	TBD	Modified R9 to include the Generator Interconnection Facility. Added a new Requirement R13	Addition

A. Introduction

1. **Title:** **Steady-State Data for Modeling and Simulation of the Interconnected Transmission System**

2. **Number:** MOD-010-X~~0~~

3. **Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the Interconnected Transmission Systems.

4. **Applicability:**

   4.1. Transmission Owners specified in the data requirements and reporting procedures of MOD-011-0_R1

   4.2. Transmission Planners specified in the data requirements and reporting procedures of MOD-011-0_R1

   4.3. Generator Owners specified in the data requirements and reporting procedures of MOD-011-0_R1

   4.4. Resource Planners specified in the data requirements and reporting procedures of MOD-011-0_R1

5. **Effective Date:** ~~April 1, 2005~~TBD

B. Requirements

R1. The Transmission Owners, Transmission Planners Generator Owners (for plant and Generator Interconnection Facility), and Resource Planners ~~-~~(specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R1.

R2. The Transmission Owners, Transmission Planners, Generator Owners (for plant and Generator Interconnection Facility), and Resource Planners ~~-~~(specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide this steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R1. If no schedule exists, then these entities shall provide the data on request (30 calendar days).

C. Measures

M1. The Transmission Owner, Transmission Planner, Generator Owner, and Resource Planner, (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall have evidence that it provided equipment characteristics, system data, and Interchange Schedules for steady-state modeling and simulation to the Regional Reliability Organizations and NERC as specified in Standard MOD-010-0_R1 and MOD-010-0_R2.

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organizations.

   1.2. Compliance Monitoring Period and Reset Timeframe

As specified within the applicable reporting procedures (Reliability Standard MOD-011-0_R2-M1). If no schedule exists, then on request (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Steady-state data was provided, but was incomplete in one of the seven areas identified in Reliability Standard MOD-011-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Steady-state data was provided, but was incomplete in two or more of the seven areas identified in Reliability Standard MOD-011-0_R1.

2.4. Level 4: Steady-state data was not provided.

E. Regional Differences

~~1.~~None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
X	TBD	Modified R1 and R2 to include plant and Generator Interconnection Facility	Addition

A. Introduction

1. **Title:** **Dynamics Data for Modeling and Simulation of the Interconnected Transmission System.**

2. **Number:** MOD-012-X~~0~~

3. **Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.

4. **Applicability:**

   4.1. Transmission Owners specified in the data requirements and reporting procedures of MOD-013-0_R1

   4.2. Transmission Planners specified in the data requirements and reporting procedures of MOD-013-0_R1

   4.3. Generator Owners specified in the data requirements and reporting procedures of MOD-013-0_R1

   4.4. Resource Planners specified in the data requirements and reporting procedures of MOD-013-0_R1

5. **Effective Date:** ~~April 1, 2005~~TBD

B. Requirements

R1. The Transmission Owners, Transmission Planners, Generator Owners (for plant and Generator Interconnection Facility), and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R1.

R2. The Transmission Owners, Transmission Planners, Generator Owners (for plant and Generator Interconnection Facility), and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall provide dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R1. If no schedule exists, then these entities shall provide data on request (30 calendar days).

C. Measures

M1. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall each have evidence that it provided equipment characteristics and system data for dynamics system modeling and simulation in accordance with Reliability Standard MOD-012-0_R1 and Reliability Standard MOD-012-0_R2.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

As specified within the applicable reporting procedures (Reliability Standard MOD-013-0). If no schedule exists, then on request (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Dynamics data was provided, but was incomplete in one of the four areas identified in Reliability Standard MOD-013-0_R1.

2.2. Level 2: Not Applicable.

2.3. Level 3: Dynamics data was provided, but was incomplete in two or more of the four areas identified in Reliability Standard MOD-013-0_R1.

2.4. Level 4: Dynamics data was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	September 16, 2005	Changed references to MOD-013-0 R4 to MOD-013-0 R1 in Applicability, Requirements, and Measures (4 in all).	Errata
X	TBD	Modified R1 and R2 to include plant and Generator Interconnection Facility	Addition

A. Introduction

1. **Title:** **Operating Personnel Responsibility and Authority**

2. **Number:** PER-001-X~~0~~

3. **Purpose:** Transmission Operator and Balancing Authority operating personnel must have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

   4.3. Generator Operators.

5. **Effective Date:** ~~April 1, 2005~~TBD

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

R2. Each Generator Operator shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and Generation Interconnection Facility, and the responsibility and authority to follow the directives of reliability authorities including the Transmission Operator and Balancing Authority.

C. Measures

M1. The Transmission Operator and Balancing Authority provide documentation that operating personnel have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System. These responsibilities and authorities are understood by the operating personnel. Documentation shall include:

M1.1 A written current job description that states in clear and unambiguous language the responsibilities and authorities of each operating position of a Transmission Operator and Balancing Authority. The position description identifies personnel subject to the authority of the Transmission Operator and Balancing Authority.

M1.2 The current job description is readily accessible in the control room environment to all operating personnel.

M1.3 A written current job description that states operating personnel are responsible for complying with the NERC reliability standards.

M1.4 Written operating procedures that state that, during normal and emergency conditions, operating personnel have the authority to take or direct timely and appropriate real-time actions. Such actions shall include shedding of firm load to prevent or alleviate System Operating Limit Interconnection or Reliability Operating Limit violations. These actions are performed without obtaining approval from higher-level personnel within the Transmission Operator or Balancing Authority.

D. Compliance

1. **Compliance Monitoring Process**

Periodic Review: An on-site review including interviews with Transmission Operator and Balancing Authority operating personnel and document verification will be conducted every three years. The job description identifying operating personnel authorities and responsibilities will be reviewed, as will the written operating procedures or other documents delineating the authority of the operating personnel to take actions necessary to maintain the reliability of the Bulk Electric System during normal and emergency conditions.

1.1. Compliance Monitoring Responsibility

Self-certification: The Transmission Operator and Balancing Authority shall annually complete a self-certification form developed by the Regional Reliability Organization based on measures M1.1 to M1.4.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

Permanent.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: The Transmission Operator or Balancing Authority has written documentation that includes three of the four items in M1.

2.2. Level 2: The Transmission Operator or Balancing Authority has written documentation that includes two of the four items in M1.

2.3. Level 3: The Transmission Operator or Balancing Authority has written documentation that includes one of the four items in M1.

2.4. Level 4: The Transmission Operator or Balancing Authority has written documentation that includes none of the items in M1, or the personnel interviews indicate Transmission Operator or Balancing Authority do not have the required authority.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
X	TBD	Added new Requirement R2 Added Generator Operators to the Applicability Section	Addition

A. Introduction

1. **Title:** **Operating Personnel Training**

2. **Number:** PER-002-X~~0~~

3. **Purpose:** Each Transmission Operator and Balancing Authority must provide their personnel with a coordinated training program that will ensure reliable system operation.

4. **Applicability**

   4.1. Balancing Authority.

   4.2. Transmission Operator.

   4.3. Generator Operator.

5. **Effective Date:** ~~April 1, 2005~~TBD

B. Requirements

R1. Each Transmission Operator, Generator Operator, and Balancing Authority shall be staffed with adequately trained operating personnel.

R2. Each Transmission Operator and Balancing Authority shall have a training program for all operating personnel that are in:

R2.1. Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.

R2.2. Positions directly responsible for complying with NERC standards.

R3. Each Generator Operator shall implement an initial and continuing training program for all operating personnel that are responsible for operating the Generator Interconnection Facility that verifies the personnel's ability and understanding to operate the equipment in a reliable manner.

~~R3.~~R4. For personnel identified in Requirement R2, the Transmission Operator and Balancing Authority shall provide a training program meeting the following criteria:

~~R3.1.~~R4.1. A set of training program objectives must be defined, based on NERC and Regional Reliability Organization standards, entity operating procedures, and applicable regulatory requirements. These objectives shall reference the knowledge and competencies needed to apply those standards, procedures, and requirements to normal, emergency, and restoration conditions for the Transmission Operator and Balancing Authority operating positions.

~~R3.2.~~R4.2. The training program must include a plan for the initial and continuing training of Transmission Operator and Balancing Authority operating personnel. That plan shall address knowledge and competencies required for reliable system operations.

~~R3.3.~~R4.3. The training program must include training time for all Transmission Operator and Balancing Authority operating personnel to ensure their operating proficiency.

~~R3.4.~~R4.4. Training staff must be identified, and the staff must be competent in both knowledge of system operations and instructional capabilities.

~~R4.~~R5. For personnel identified in Requirement R2, each Transmission Operator and Balancing Authority shall provide its operating personnel at least five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.

C. Measures

M1. The Transmission Operator and Balancing Authority operating personnel training program shall be reviewed to ensure that it is designed to promote reliable system operations.

D. Compliance

1. Compliance Monitoring Process

Periodic Review: The Regional Reliability Organization will conduct an on-site review of the Transmission Operator and Balancing Authority operating personnel training program every three years. The operating personnel training records will be reviewed and assessed compared to the program curriculum.

1.1. Compliance Monitoring Responsibility

Self-certification: The Transmission Operator and Balancing Authority will annually provide a self-certification based on Requirements R1 through R4.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

Three years.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: N/A.

2.2. Level 2: The Transmission Operator or Balancing Authority operating personnel training program does not address all elements of Requirement R3.

2.3. Level 3: The Transmission Operator or Balancing Authority operating personnel training program does not address Requirement R4.

2.4. Level 4: A Transmission Operator or Balancing Authority has not provided a training program for its operating personnel.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Proposed Effective Date	Errata
X	TBD	Modified R1 and the Applicability Section to include Generator Operator Added new Requirement R3	Addition

A. Introduction

1. **Title:** **System Protection Coordination**
2. **Number:** PRC-001-X~~1~~
3. **Purpose:**

   To ensure system protection is coordinated among operating entities.
4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators
5. **Effective Date:** ~~January 1, 2007~~TBD

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area, including those for the Generator Interconnection Facility.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures, including those for the Generator Interconnection Facility, as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes, including those for the Generator Interconnection Facility, as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes, including those for the Generator Interconnection Facility, with its Transmission Operator and Host Balancing Authority.

R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

R4. Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions, including those for the Generator Interconnection Facility, that could require changes in the protection systems of others:

R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions, including those for the Generator Interconnection Facility, that could require changes in the Transmission Operator's protection systems.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.

R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)

M3. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)

- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

3. Levels of Non-Compliance for Transmission Operators:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

3.4.2 Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
X	TBD	Modified R1, R2, R3, R3.1, R5, and R5.1 to include the Generator Interconnection Facility.	Addition

A. Introduction

1. **Title:** **Analysis and Mitigation of Transmission and Generation Protection System Misoperations**

2. **Number:** PRC-004-X~~1~~

3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Distribution Provider that owns a transmission Protection System.

   4.3. Generator Owner.

5. **Effective Date:** ~~August 1, 2006~~ TBD

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1.

R2. The Generator Owner shall analyze its generator Protection System Misoperations, including those for the Generator Interconnection Facility, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization procedures developed for PRC-003 R1.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Reliability Organization procedures developed for PRC-003 R1.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Transmission Owners and Distribution Providers that own a Transmission Protection System:

2.1. Level 1: Documentation of Misoperations is complete according to PRC-004 R1, but documentation of Corrective Action Plans is incomplete.

2.2. Level 2: Documentation of Misoperations is incomplete according to PRC-004 R1 and documentation of Corrective Action Plans is incomplete.

2.3. Level 3: Documentation of Misoperations is incomplete according to PRC-004 R1 and there are no associated Corrective Action Plans.

2.4. Level 4: Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to Requirement 3.

3. Levels of Non-Compliance for Generator Owners

3.1. Level 1: Documentation of Misoperations is complete according to PRC-004 R2, but documentation of Corrective Action Plans is incomplete.

3.2. Level 2: Documentation of Misoperations is incomplete according to PRC-004 R2 and documentation of Corrective Action Plans is incomplete.

3.3. Level 3: Documentation of Misoperations is incomplete according to PRC-004 R2 and there are no associated Corrective Action Plans.

3.4. Level 4: Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to R3.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 2. Added "periods" to items where appropriate. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
X	TBD	Modified R2 to include the Generator Interconnection Facility	Addition

A. Introduction

1. **Title:** **Transmission and Generation Protection System Maintenance and Testing**

2. **Number:** PRC-005-X~~1~~

3. **Purpose:** To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Generator Owner.

   4.3. Distribution Provider that owns a transmission Protection System.

5. **Effective Date:** ~~May 1, 2006~~

B. Requirements

R1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System, including those for the Generator Interconnection Facility, shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:

R1.1. Maintenance and testing intervals and their basis.

R1.2. Summary of maintenance and testing procedures.

R2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System, including those for the Generator Interconnection Facility shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:

R2.1. Evidence Protection System devices were maintained and tested within the defined intervals.

R2.2. Date each Protection System device was last tested/maintained.

C. Measures

M1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System that affects the reliability of the BES, shall have an associated Protection System maintenance and testing program as defined in Requirement 1.

M2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System that affects the reliability of the BES, shall have evidence it provided documentation of its associated Protection System maintenance and testing program and the implementation of its program as defined in Requirement 2.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System, shall retain evidence of the implementation of its Protection System maintenance and testing program for three years.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and the Generator Owner that owns a generation Protection System, shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of the maintenance and testing program provided was incomplete as required in R1, but records indicate maintenance and testing did occur within the identified intervals for the portions of the program that were documented.

2.2. Level 2: Documentation of the maintenance and testing program provided was complete as required in R1, but records indicate that maintenance and testing did not occur within the defined intervals.

2.3. Level 3: Documentation of the maintenance and testing program provided was incomplete, and records indicate implementation of the documented portions of the maintenance and testing program did not occur within the identified intervals.

2.4. Level 4: Documentation of the maintenance and testing program, or its implementation, was not provided.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash” (—). 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame”	01/20/05

		in item D, 1.2.	
X	TBD	Modified R1 and R2 to include the Generator Interconnection Facility	Additions

A. Introduction

1. **Title:** **Reliability Responsibilities and Authorities**

2. **Number:** TOP-001-X~~1~~

3. **Purpose:**

   To ensure reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

   4.4. Distribution Providers

   4.5. Load Serving Entities

5. **Effective Date:** ~~January 1, 2007~~TBD

B. Requirements

R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.

R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.

R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.

R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.

R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.

R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities, including the Generator Interconnection Facility, from service if removing those facilities would burden neighboring systems unless:

~~1.~~**R7.1.** For a generator outage, including the Generator Interconnection Facility, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.

~~2.~~**R7.2.** For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.

~~3.~~**R7.3.** When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.

R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.

R9. The Generator Operator, in accord with the expectations defined by the Transmission Operator, shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects in order to preserve Interconnection reliability with respect to the following:

- Switching elements
- Outage planning
- Real-time or anticipated emergency conditions
- Other conditions mutually agreed upon by the Generator Operator and Transmission Operator

R10. The Transmission Operator shall have decision-making authority over operation of the Generator Interconnection Operational Interface at all times in order to preserve Interconnection reliability.

~~The Generator Operator shall take the action it deems appropriate to remove from service the Generator Interconnection Facilities when safety is jeopardized or equipment damage is imminent.~~

~~The Generator Operator shall notify the Transmission Operator as soon as practical of the actions taken and the reasons therein.~~

C. Measures

M1. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, signed agreements, an authority letter signed by an officer of the company, or other equivalent evidence that will be used to confirm that it has the authority, and has exercised the authority, to alleviate operating emergencies as described in Requirement 1.

M2. If an operating emergency occurs the Transmission Operator that experienced the emergency shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it took immediate actions to alleviate the operating emergency including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc. (Requirement 2)

M3. Each Transmission Operator, Balancing Authority, and Generator Operator shall have and provide upon request evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Reliability Coordinator's reliability directives. If the Transmission Operator, Balancing Authority or Generator Operator did not comply with the directive because it would violate safety, equipment, regulatory or statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Reliability Coordinator of its inability to perform the directive. (Requirement 3)

M4. Each Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity shall have and provide upon request evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Transmission Operator's reliability directives. If the Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity did not comply with the directive because it would violate safety, equipment, regulatory or statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Transmission Operator of its inability to perform the directive. (Requirements 3 and 4)

M5. The Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it informed its Reliability Coordinator and any other potentially affected

Transmission Operators of real time or anticipated emergency conditions, and took actions to avoid, when possible, or to mitigate an emergency. (Requirement 5)

M6. The Transmission Operator, Balancing Authority, and Generator Operator shall each have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it rendered assistance to others as requested, provided that the requesting entity had implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements. (Requirement 6)

M7. The Transmission Operator and Generator Operator shall each have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it notified either their Transmission Operator in the case of the Generator Operator, or other Transmission Operators, and the Reliability Coordinator when it removed Bulk Electric System facilities from service if removing those facilities would burden neighboring systems. (Requirement 7)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Transmission Operator shall have the current in-force document to show that it has the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area. (Measure 1)

Each Transmission Operator shall keep 90 days of historical data (evidence) for Measures 1 through 7, including evidence of directives issued for Measures 3 and 4.

Each Balancing Authority shall keep 90 days of historical data (evidence) for Measures 3, 4 and 6 including evidence of directives issued for Measures 3 and 4.

Each Generator Operator shall keep 90 days of historical data (evidence) for Measures 3, 4, 6 and 7 including evidence of directives issued for Measures 3 and 4.

Each Distribution Provider and Load-serving Entity shall keep 90 days of historical data (evidence) for Measure 4.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for a Balancing Authority:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not comply with a Reliability Coordinator's or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive (R3)

2.4.2 Did not render emergency assistance to others as requested, in accordance with R6.

3. Levels of Non-Compliance for a Transmission Operator

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Does not have the documented authority to act as specified in R1.

3.4.2 Does not have evidence it acted with the authority specified in R1.

3.4.3 Did not take immediate actions to alleviate operating emergencies as specified in R2.

3.4.4 Did not comply with its Reliability Coordinator's reliability directive or did not immediately inform the Reliability Coordinator of its inability to perform that directive, as specified in R3.

3.4.5 Did not inform its Reliability Coordinator and other potentially affected Transmission Operators of real time or anticipated emergency conditions as specified in R5.

3.4.6 Did not take actions to avoid, when possible, or to mitigate an emergency as specified in R5.

3.4.7 Did not render emergency assistance to others as requested, as specified in R6.

3.4.8 Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and removing those facilities burdened a neighbor system.

4. Levels of Non-Compliance for a Generator Operator:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

4.4.1 Did not comply with a Reliability Coordinator or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive, as specified in R3.

4.4.2 Did not render all available emergency assistance to others as requested, unless such actions would violate safety, equipment, or regulatory or statutory requirements as specified in R6.

4.4.3 Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and burdened a neighbor system.

5. Levels of Non-Compliance for a Distribution Provider or Load Serving Entity

5.1. Level 1: Not applicable.

5.2. Level 2: Not applicable.

5.3. Level 3: Not applicable

5.4. **Level 4:** Did not comply with a Transmission Operator's reliability directive or immediately inform the Transmission Operator of its inability to perform that directive, as specified in R4.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
X	TBD	Modified R7 and R7.1 to include the Generator Interconnection Facility Added new Requirements R~~1~~9 and~~,~~ R10~~, and R11~~.	Addition

A. Introduction

1. **Title:** **Normal Operations Planning**
2. **Number:** TOP-002-X~~2~~
3. **Purpose:** Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.
4. **Applicability**
   - **4.1.** Balancing Authority.
   - **4.2.** Transmission Operator.
   - **4.3.** Generator Operator.
   - **4.4.** Load Serving Entity.
   - **4.5.** Transmission Service Provider.
5. **Effective Date:** ~~**January 1, 2007**~~TBD

   Six months after effective date of VAR-001-1.

B. Requirements

R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.

R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.

R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations, including for the Generator Interconnection Facility, with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.

R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.

R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.

R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.

R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.

R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.

R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.

R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.

R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:

R14.1. Changes in real and reactive output capabilities. (Retired August 1, 2007)

R14.1. Changes in real output capabilities. (Effective August 1, 2007)

R14.2. Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)

R14.2. Changes in Generator Interconnection Facility Status

R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).

R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:

R16.1. Changes in transmission facility status.

R16.2. Changes in transmission facility rating.

R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.

R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network and for the Generator Interconnection Facility.

R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.

C. Measures

M1. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, documented planning procedures, copies of current day plans, copies of seasonal operations plans, or other equivalent evidence that will be used to confirm that it maintained a set of current plans. (Requirement 1 Part 1).

M2. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 5, 6, and 10.

M3. Each Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 7, 8, and 9.

M4. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, its next-day, and current-day Bulk Electric System studies used to determine SOLs or other equivalent evidence that will be used to confirm that its studies reflect current system conditions. (Requirement 11 Part 1)

M5. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that the results of Bulk Electric System studies were made available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator. (Requirement 11 Part 2)

M6. Each Generator Operator shall have and provide upon request evidence that, when requested by either a Transmission Operator or Balancing Authority, it performed a generating real and reactive capability verification and provided the results to the requesting entity in accordance with Requirement 13.

M7. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that without any intentional time delay, it notified its Balancing Authority and Transmission Operator of changes in real and reactive capabilities and AVR status. (Requirement 14)

M8. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, on request, it provided a forecast of expected real power output to assist in operations planning. (Requirement 15)

M9. Each Transmission Operators shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, without any intentional time delay, it notified its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics. (Requirement16)

M10. Each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to, a list of interconnected transmission facilities and their line identifiers at each end or other equivalent evidence that will be used to confirm that it used uniform line identifiers when referring to transmission facilities of an interconnected network. (Requirement 18)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 calendar days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measures 1 and 2, each Transmission Operator shall have its current plans and a rolling 6 months of historical records (evidence).

For Measures 1, 2, and 3 each Balancing Authority shall have its current plans and a rolling 6 months of historical records (evidence).

For Measure 4, each Transmission Operator shall keep its current plans (evidence).

For Measures 5 and 9, each Transmission Operator shall keep 90 days of historical data (evidence).

For Measures 6, 7 and 8, each Generator Operator shall keep 90 days of historical data (evidence).

For Measure 10, each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider, and Load-serving Entity shall have its current list interconnected transmission facilities and their line identifiers at each end or other equivalent evidence as evidence.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Balancing Authorities:

2.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not maintain an updated set of current-day plans as specified in R1.

2.4.2 Plans did not meet one or more of the requirements specified in R5 through R10.

3. Levels of Non-Compliance for Transmission Operators

3.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

3.2. Level 2: Not applicable.

3.3. Level 3: One or more of Bulk Electric System studies were not made available as specified in R11.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Did not maintain an updated set of current-day plans as specified in R1.

3.4.2 Plans did not meet one or more of the requirements in R5, R6, and R10.

3.4.3 Studies not updated to reflect current system conditions as specified in R11.

3.4.4 Did not notify its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics as specified in R16.

4. Levels of Non-Compliance for Generator Operators:

4.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

4.4.1 Did not verify and provide a generating real and reactive capability verification and provide the results to the requesting entity as specified in R13.

4.4.2 Did not notify its Balancing Authority and Transmission Operator of changes in capabilities and characteristics as specified in R14.

4.4.3 Did not provide a forecast of expected real power output to assist in operations planning as specified in R15.

5. Levels of Non-Compliance for Transmission Service Providers and Load-serving Entities:

5.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

5.2. Level 2: Not applicable.

5.3. Level 3: Not applicable.

5.4. Level 4: Not applicable.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
X	TBD	Modified R3 and R18 to include the Generator Interconnection Facility and added Requirement R14.3.	Addition

A. Introduction

1. **Title:** **Planned Outage Coordination**
2. **Number:** TOP-003-X~~0~~
3. **Purpose:** Scheduled generator and transmission outages that may affect the reliability of interconnected operations must be planned and coordinated among Balancing Authorities, Transmission Operators, and Reliability Coordinators.
4. **Applicability**
   - **4.1.** Generator Operators.
   - **4.2.** Transmission Operators.
   - **4.3.** Balancing Authorities.
   - **4.4.** Reliability Coordinators.
5. **Effective Date:** ~~April 1, 2005~~TBD

B. Requirements

R1. Generator Operators and Transmission Operators shall provide planned outage information, including information for the Generator Interconnection Facility.

R1.1. Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW) or the Generator Interconnection Facility. The Transmission Operator shall establish the outage reporting requirements.

R1.2. Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements.

R1.3. Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.

R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.

R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.

C. Measures

M1. Evidence that the Generator Operator, Transmission Operator, Balancing Authority, and Reliability Coordinator reported and coordinated scheduled outage information as indicated in the requirements above.

D. Compliance

1. Compliance Monitoring Process

Each Regional Reliability Organization shall conduct a review every three years to ensure that each responsible entity has a process in place to provide planned generator and/or bulk transmission outage information to their Reliability Coordinator, and with neighboring Transmission Operators and Balancing Authorities.

Investigation: At the discretion of the Regional Reliability Organization or NERC, an investigation may be initiated to review the planned outage process of a monitored entity due to a complaint of non-compliance by another entity. Notification of an investigation must be made by the Regional Reliability Organization to the entity being investigated as soon as possible, but no later than 60 days after the event. The form and manner of the investigation will be set by NERC and/or the Regional Reliability Organization.

1.1. Compliance Monitoring Responsibility

A Reliability Coordinator makes a request for an outage to “not be taken” because of a reliability impact on the grid and the outage is still taken. The Reliability Coordinator must provide all its documentation within three business days to the Regional Reliability Organization. Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year without a violation from the time of the violation.

1.3. Data Retention

One calendar year.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: Each entity responsible for reporting information under Requirements R1 and R3 has a process in place to provide information to their Reliability Coordinator but does not have a process in place (where permitted by legal agreements) to provide this information to the neighboring Balancing Authority or Transmission Operator.

2.2. Level 2: N/A.

2.3. Level 3: N/A.

2.4. Level 4: There is no process in place to exchange outage information, or the entity responsible for reporting information under Requirements R1 to R3 does not follow the directives of the Reliability Coordinator to cancel or reschedule an outage.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
X	TBD	Modified R1 and R1.1 to include the Generator Interconnection Facility	Addition

A. Introduction

1. **Title:** **Transmission Operations**
2. **Number:** TOP-004-X~~2~~
3. **Purpose:** To ensure that the transmission system is operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single Contingency and specified multiple Contingencies.
4. **Applicability:**
   4.1. Transmission Operators
5. **Proposed Effective Date:** ~~Twelve months after BOT adoption of FAC-014~~TBD.

B. Requirements

R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).

R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.

R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.

R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.

R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.

R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:

R6.1. Monitoring and controlling voltage levels and real and reactive power flows.

R6.2. Switching transmission elements.

R6.3. Planned outages of transmission elements.

R6.4. Responding to IROL and SOL violations.

R7. The Generator Operator shall operate its Generator Interconnection Facility within its applicable ratings.

C. Measures

M1. Each Transmission Operator that enters an unknown operating state for which valid limits have not been determined, shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it restored operations to respect proven reliable power system limits within 30 minutes as specified in Requirement 4.

M2. Each Transmission Operator shall have and provide upon request current policies and procedures that address the execution and coordination of activities that impact inter- and intra-Regional reliability for each of the topics listed in Requirements 6.1 through 6.6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Transmission Operator shall keep 90 days of historical data for Measure 1.

Each Transmission Operator shall have current, in-force policies and procedures, as evidence of compliance to Measure 2.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance:

2.1. Level 1: Not applicable.

2.2. Level 2: Did not have formal policies and procedures to address one of the topics listed in R6.1 through R6.4.

2.3. .**Level 3:** Did not have formal policies and procedures to address two of the topics listed in R6.1 through R6.4.

2.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not restore operations to respect proven reliable power system limits within 30 minutes as specified in R4.

2.4.2 Did not have formal policies and procedures to address three or all of the topics listed in R6.1 through R6.4.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Added language from Missing Measures and Compliance Elements adopted by Board of Trustees on November 1, 2006	Revised
2	December 19, 2007	Revised to reflect merging of both sets of changes approved by BOT on November 1, 2006 (Addition of measures and compliance elements and revisions to R3 and R6 with conforming changes made as errata to Levels of Non-compliance)	Revised Errata
X	TBD	Added Requirement R7	Addition

A. Introduction

1. **Title:** **Response to Transmission Limit Violations**

2. **Number:** TOP-008-X~~1~~

3. **Purpose:** To ensure Transmission Operators take actions to mitigate SOL and IROL violations.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Generator Operators.

5. **Effective Date:** ~~January 1, 2007~~TBD

B. Requirements

R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.

R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.

R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.

R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.

R5. The Generator Operator shall disconnect the Generator Interconnection Facility when safety is jeopardized or if the overload or abnormal voltage or reactive condition persists and generating equipment or the Generator Interconnection Facility is endangered. In doing so, the Generator Operator shall notify its Transmission Operator and Balancing Authority impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.

C. Measures

M1. The Transmission Operator involved in an SOL or IROL violation shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it took immediate steps to relieve the condition. (Requirement 1)

M2. The Transmission Operator that disconnects an overloaded facility shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications, alarm program print outs, or other equivalent evidence that will be used to determine if it disconnected an overloaded facility in accordance with Requirement 3 Part 1

M3. The Transmission Operator that disconnects an overloaded facility shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it notified its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permitted, otherwise, immediately thereafter. (Requirement 3 Part 2)

M4. The Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, computer facilities documents, computer printouts, training documents, copies of analysis program results, operator logs or other equivalent evidence that will be used to confirm that it has sufficient information and analysis tools to determine the cause(s) of SOL violations. (Requirement 4 Part 1)

M5. The Transmission Operator that violates an SOL shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it used the results of these analyses to immediately mitigate the SOL violation. (Requirement 4 Part 3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Transmission Operator shall keep 90 days of historical data (evidence) for Measure 1, 2 and 3.

Each Transmission Operator shall have current documents as evidence of compliance to Measures 4 and 5.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Transmission Operator

2.1. Level 1: Not applicable.

2.2. Level 2: Disconnected an overloaded facility as specified in R3 but did not notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, or immediately thereafter.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not take immediate steps to relieve an IROL or SOL violation in accordance with R1.

2.4.2 Did not disconnect an overloaded facility as specified in R3.

2.4.3 Does not have sufficient information and analysis tools to determine the cause(s) of SOL violations. (R4 Part 1)

2.4.4 Did not use the results of analyses to immediately mitigate an SOL violation. (R4 Part 3)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
X	TBD	Added new Requirement R5	Addition

A. Introduction

1. **Title:** **Voltage and Reactive Control**
2. **Number:** VAR-001-X~~1~~
3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the Interconnection.
4. **Applicability:**
   - **4.1.** Transmission Operators.
   - **4.2.** Purchasing-Selling Entities.
5. **Effective Date:** ~~Six months after BOT adoption.~~TBD

B. Requirements

R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.

R2. Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.

R3. The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.

R3.1. Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.

R3.2. For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.

R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule [1] at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage).

R5. Each Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its Transmission Service Provider.

R6. The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.

R6.1. When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.

R7. The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.

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[1] The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.

R8. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line, Generator Interconnection Facility, and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.

R9. Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.

R9.1. Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.

R10. Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.

R11. After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.

R12. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

C. Measures

M1. The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule as specified in Requirement 4 to each Generator Operator it requires to follow such a schedule.

M2. The Transmission Operator shall have evidence to show that, for each generating unit in its area that is exempt from following a voltage or Reactive Power schedule, the associated Generator Owner was notified of this exemption in accordance with Requirement 3.2.

M3. The Transmission Operator shall have evidence to show that it issued directives as specified in Requirement 6.1 when notified by a Generator Operator of the loss of an automatic voltage regulator control.

M4. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with Requirement 11.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Operator shall retain evidence for Measures 1 through 4 for 12 months.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Operator shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: No evidence that exempt Generator Owners were notified of their exemption as specified under R3.2

2.2. Level 2: There shall be a level two non-compliance if either of the following conditions exists:

2.2.1 No evidence to show that directives were issued in accordance with R6.1.

2.2.2 No evidence that documentation was provided to Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with R11.

2.3. Level 3: There shall be a level three non-compliance if either of the following conditions exists:

2.3.1 Voltage or Reactive Power schedules were provided for some but not all generating units as required in R4.

2.4. Level 4: No evidence voltage or Reactive Power schedules were provided to Generator Operators as required in R4.

D. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	July 3, 2007	Added "Generator Owners" and "Generator Operators" to Applicability section.	Errata
1	August 23, 2007	Removed "Generator Owners" and "Generator Operators" to Applicability section.	Errata
X	TBD	Modified R8 to include Generator Interconnection Facility	Addition

A. Introduction

1. **Title:** **Generator Operation for Maintaining Network Voltage Schedules**

2. **Number:** VAR-002-X~~1.1~~a

3. **Purpose:** To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.

4. **Applicability**

   4.1. Generator Operator.

   4.2. Generator Owner.

5. **Effective Date:** ~~May 13, 2009~~TBD

B. Requirements

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings[1]) as directed by the Transmission Operator.

R2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:

R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control, including the Generator Interconnection Facility, and the expected duration of the change in status or capability.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

R4.1. For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:

R4.1.1. Tap settings.

R4.1.2. Available fixed tap ranges.

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[1] When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this will lead to a change in the associated Facility Ratings.

R4.1.3. Impedance data.

R4.1.4. The +/- voltage range with step-change in % for load-tap changing transformers.

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.

R5.1. If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.

C. Measures

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1.

M2. The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator as specified in Requirement 2.

M3. The Generator Operator shall have evidence to show that it responded to the Transmission Operator's directives as identified in Requirement 2.1 and Requirement 2.2.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.4

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation as identified in Requirement 5.

M7. The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn't comply with the Transmission Operator's step-up transformer tap specifications as identified in Requirement 5.1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Generator Operator shall maintain evidence needed for Measure 1 through Measure 5 and Measure 7 for the current and previous calendar years.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. (Measure 6)

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Generator Owner and Generator Operator shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Generator Operator

2.1. Level 1: There shall be a Level 1 non-compliance if any of the following conditions exist:

2.1.1 One incident of failing to notify the Transmission Operator as identified in , R3.1, R3.2 or R5.1.

2.1.2 One incident of failing to maintain a voltage or reactive power schedule (R2).

2.2. Level 2: There shall be a Level 2 non-compliance if any of the following conditions exist:

2.2.1 More than one but less than five incidents of failing to notify the Transmission as identified in R1, R3.1,R3.2 or R5.1.

2.2.2 More than one but less than five incidents of failing to maintain a voltage or reactive power schedule (R2).

2.3. Level 3: There shall be a Level 3 non-compliance if any of the following conditions exist:

2.3.1 More than five but less than ten incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.3.2 More than five but less than ten incidents of failing to maintain a voltage or reactive power schedule (R2).

2.4. Level 4: There shall be a Level 4 non-compliance if any of the following conditions exist:

2.4.1 Failed to comply with the Transmission Operator's directives as identified in R2.

2.4.2 Ten or more incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.4.3 Ten or more incidents of failing to maintain a voltage or reactive power schedule (R2).

3. Levels of Non-Compliance for Generator Owner:

3.1.1 **Level One:** Not applicable.

3.1.2 **Level Two:** Documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage was missing two of the data types identified in R4.1.1 through R4.1.4.

3.1.3 **Level Three:** No documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage

3.1.4 **Level Four:** Did not ensure generating unit step-up transformer settings were changed in compliance with the specifications provided by the Transmission Operator as identified in R5.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 – Interpretation of Requirements R1 and R2 (August 1, 2007).

Version History

Version	Date	Action	Change Tracking
1	May 15, 2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	December 19, 2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	January 16, 2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
1.1a	October 29, 2008	BOT adopted errata changes; updated version number to "1.1a"	Errata
1.1a	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
X	TBD	Modified R3.2 to include the Generator Interconnection Facility	Addition

Appendix 1

Interpretation of Requirements R1 and R2

Request:

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (***automatic voltage regulator in service and controlling voltage***) unless the Generator Operator has notified the Transmission Operator.

Requirement R2 goes on to state that each Generation Operator shall maintain the generator voltage ***or Reactive Power output*** as directed by the Transmission Operator.

The two underlined phrases are the reasons for this interpretation request.

Most generation excitation controls include a device known as the Automatic Voltage Regulator, or AVR. This is the device which is referred to by the R1 requirement above. Most AVR's have the option of being set in various operating modes, such as constant voltage, constant power factor, and constant Mvar.

In the course of helping members of the WECC insure that they are in full compliance with NERC Reliability Standards, I have discovered both Transmission Operators and Generation Operators who have interpreted this standard to mean that AVR operation in the constant power factor or constant Mvar modes complies with the R1 and R2 requirements cited above. Their rational is as follows:

- The AVR is clearly in service because it is operating in one of its operating modes
- The AVR is clearly controlling voltage because to maintain constant PF or constant Mvar, it controls the generator terminal voltage
- R2 clearly gives the Transmission Operator the option of directing the Generation Operator to maintain a constant reactive power output rather than a constant voltage.

Other parties have interpreted this standard to require operation in the constant voltage mode only. Their rational stems from the belief that the purpose of the VAR-002-1 standard is to insure the automatic delivery of additional reactive to the system whenever a voltage decline begins to occur.

The material impact of misinterpretation of these standards is twofold.

- First, misinterpretation may result in reduced reactive response during system disturbances, which in turn may contribute to voltage collapse.
- Second, misinterpretation may result in substantial financial penalties imposed on generation operators and transmission operators who believe that they are in full compliance with the standard.

In accordance with the NERC Reliability Standards Development Procedure, I am requesting that a formal interpretation of the VAR-002-1 standard be provided. Two specific questions need to be answered.

- First, does AVR operation in the constant PF or constant Mvar modes comply with R1?
- Second, does R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

Interpretation:

1. First, does AVR operation in the constant PF or constant Mvar modes comply with R1?

   Interpretation: No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage.

2. Second, does R2 give the Transmission Operator the option of directing the Generation Owner (sic) to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

   Interpretation: Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed.